At What Cost?
A comparative evaluation of the social costs of selected electricity generation alternatives in Ontario

by

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AUTHOR’S DECLARATION FOR ELECTRONIC SUBMISSION OF A THESIS

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Abstract

This thesis examines the private and external costs of electricity generated in Ontario by natural gas, wind, refurbished nuclear and new nuclear power. The purpose of the assessment is to determine a capacity expansion plan that meets the forecasted electricity supply gap in Ontario at the lowest social costs (i.e. the lowest aggregated private and external costs). A levelized unit electricity cost (LUEC) analysis is employed to evaluate private costs under both public and merchant perspectives. Computable external costs are monetized by adapting estimates from the literature that were previously developed using a primarily bottom-up damage cost method.

The findings reveal that social cost estimates for nuclear refurbishment are the lowest of the generation alternatives studied regardless of the evaluation perspective. Therefore, if the capacity expansion decision were based solely on these estimates, nuclear refurbishment should be utilized until its capacity constraints are reached. The generation alternative with the second lowest social costs depends on the perspective from which private costs are evaluated: from a public perspective, the remainder of the supply gap should be filled by new nuclear generation and from a merchant perspective, which is assumed to be more reflective of the current Ontario electricity market, natural gas-fired generation should be used.

Due to inherent uncertainty and limitations associated with the estimation of social costs, the estimates obtained in this thesis are considered to be context and data specific. A sensitivity analysis, which is employed to attempt to mitigate some of the uncertainty, shows that changes to key variables alter the capacity expansion plan. This reinforces the observation that methods and assumptions significantly affect social cost estimates.

Despite the limitations of this kind of evaluation, it is argued that a social cost assessment that is consistent, transparent and comprehensive can be a useful tool to assess the trade-offs of electricity generation alternatives if used along with existing evaluation criteria. Such an assessment can increase the likelihood that actual social costs are minimized, which can steer electricity generation in Ontario towards a system that is more efficient and sustainable.

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List of acronyms and abbreviations

ACF: average capacity factor
ACR: Advanced Candu Reactor
AECL: Atomic Energy of Canada Ltd.
APM: Adaptive Phased Management
AQBAT: Air Quality Benefits Assessment Tool
AQVM: Air Quality Valuation Model
Bcf: billion cubic feet
CANDU: Canadian Deuterium Uranium
CCGT: combined cycle gas turbine
CDM: conservation and demand-side management
CDN$: Canadian dollars
CHP: combined heat and power
CH_4: methane
CNSC: Canadian Nuclear Safety Commission
CO: carbon monoxide
CO_2: carbon dioxide
CVM: contingent valuation method
dB: decibel
DCF: discounted cash flow
D/E ratio: debt-to-equity ratio
EU-ETS: European Union Emissions Trading System
GDP: gross domestic product
GHG: greenhouse gas
GJ: gigajoule
GWP: global warming potential
Gy: Gray
HNO_3: nitric acid
HOEP: hourly Ontario energy price
IAEA: International Atomic Energy Agency
IESO: Independent Electricity System Operator
IPCC: Intergovernmental Panel on Climate Change
IPSP: Integrated Power System Plan
IRP: integrated resource planning
kW: kilowatt
kWh: kilowatt-hour
LCF: limited containment failure
LE: life expectancy
LFE: large final emitter
LNG: liquefied natural gas
LUEC: levelized unit electricity cost
MCF: massive containment failure
Mcf: thousand cubic feet
MMBtu: million British thermal units
MOE: Ministry of Energy
m/s: metres per second
MT: megatonne
MW: megawatt
MWh: megawatt-hour
NERC: North American Electricity Reliability Council
NFWA: Nuclear Fuel Waste Act
NIMBY: not in my backyard
NO: nitric oxide
NO_X: nitrogen oxide
NO_2: nitrogen dioxide
N_2O: nitrous oxide
NPCC: Northeast Power Coordinating Council
NPT: Non-Proliferation Treaty
NPV: net present value
NWMO: Nuclear Waste Management Organization
OEB: Ontario Energy Board
OECD: Organization of Economic Co-operation and Development
O&M: operations and maintenance
OPA: Ontario Power Authority
OPG: Ontario Power Generation
O_3: ground level ozone
PM: premature mortality
$PM_{2.5}$: particulate matter with a diameter of 2.5 microns or less
PM_{10}: particulate matter with a diameter of 10 microns or less
ppb: parts per billion
ppm: parts per million
PRA: probabilistic risk assessment
PSA: probabilistic safety assessment
PV: present value
PWR: pressurized water reactor
QALY: quality-adjusted life year

RFP: request for proposals
R/P ratio: reserve-to-production ratio
SCGT: single cycle gas turbine
SMAR: supply mix advice report
SO_2: sulphur dioxide
SO_X: sulphur oxide
Sv: Sieverts
TBq: tera-bequerel
Tcf: trillion cubic feet
t CO_2-eq: tonne of carbon dioxide equivalent
TMI: Three Mile Island
TW: terawatt
TWh: terawatt-hour
UNFCCC: United Nations Framework Convention on Climate Change
UO_2: natural uranium dioxide
UO_3: natural uranium trioxide
U_{235}: natural uranium
VOC: volatile organic compound
VOLY: value of a life year
VSL: value of a statistical life
WACC: weighted average cost of capital
WCSB: Western Canadian Sedimentary Basin
WTA: willingness to accept
WTP: willingness to pay

Chapter 1 Introduction

1.1 Electricity generation: an introduction

The benefit humans derive from electricity use is widely acknowledged. However, although electricity generation contributes to human development at a fundamental level, it is also associated with various environmental, economic and social impacts, and these vary depending on the generation alternative employed. Furthermore, these impacts pose a challenge for the efficient and sustainable allocation of resources that are used to generate electricity.

In this thesis, social costs are classified as the sum total of private costs and external costs (i.e. social costs = private costs + external costs). Private costs generally consist of the capital costs, fuel costs and operations and maintenance (O&M) costs that are incurred by producers and are passed along to consumers through the price of electricity. External costs, on the other hand, are present "when the social or economic activities of one group of persons have an impact on another group and when that impact is not fully accounted or compensated for, by the first group" (EC, 2005, p. 9). Essentially, external costs can be considered the "side effects" caused by electricity generation that are incurred by individuals in society or by ecosystems, whose costs are not internalized. Failing to minimize the social costs of electricity generation is an obstacle to the efficient and sustainable allocation of resources. Consequently, when social costs are not minimized it would be possible to re-allocate resources so that at least one person can be made better off without making others worse off and so that progress towards intragenerational and intergenerational equity may take place.

1.2 Electricity generation in Ontario

Planners who are responsible for guiding the province of Ontario's electricity system face a formidable challenge to ensure that the level of installed generation capacity is sufficient to meet demand requirements over the next two decades. Due to a forecasted annual rise in demand, the plan to close the province's coal-fired generating units and the expected decline of some currently installed nuclear generating units, a supply gap of 7,000 megawatts (MW)[1] is forecasted to occur in 2025.[2]

What is at stake if electricity system planners fail to meet the supply gap with electricity generation alternatives that have the lowest social costs? When social costs are not minimized the price of electricity does not adequately reflect the scarcity of resources used in production or various social and environmental costs that are associated with electricity generation. Consequently, it is likely that consumption will be higher than it otherwise would be due to the presence of the external costs and that such costs would be incurred by the general public and by ecosystems. This would have significant implications for the provincial economy, the public health of Ontarians and the environment. Moreover, the effects of this capacity expansion decision wouldbe felt across different scales throughout Ontario and abroad: impacts would be perceptible at household, municipality, provincial and, in some instances, global levels (Holdren and Smith, 2000).

The current criterion used by the Ontario Power Authority (OPA), which is the government agency charged with ensuring long-term supply adequacy in Ontario, to evaluate generation alternatives is to balance reliability with affordable prices and environmental and social considerations. The OPA's Integrated Power System Plan (IPSP) (scheduled to be published in 2007) will evaluate various electricity generation alternatives to fill the forecasted supply gap and will be used to set the course for electricity capacity expansion in Ontario over the next 20 years. This assessment, however, is not likely to include an explicit social cost assessment.

[1] One megawatt is equal to 1,000 kilowatts (kW). One kW is "a standard unit used to measure electric power, equal to one thousand watts. A kilowatt can be visualized as the total amount of power required to light ten 100-watt light bulbs" (Ayres et al., 2004). A conversion table that includes Watt conversion information and other conversion data is provided in Appendix A.

[2] This figure is net of already planned capacity expansion and conservation and demand-side management initiatives.

1.3 Thesis objective and contribution to the literature

In this context, this thesis assesses the social costs of selected electricity generation alternatives in Ontario to determine a capacity expansion plan that is able to meet the anticipated supply gap at the lowest social costs per kilowatt-hour (kWh).[3] Secondary data are used to derive social cost estimates for the generation alternatives in the Ontario context. However, since the methodology and the assumptions upon which social cost estimates are based tend to vary in the literature and the reliability of the data may be contentious, the credibility of the estimates is a central concern of this analysis. Consequently, this assessment aims to be consistent, transparent and comprehensive (as advocated by EC, 2005), which is intended to increase the validity of the results.

A literature review reveals that previous social cost research in Ontario contains a number of gaps. Few studies in Ontario have been carried out in a consistent, transparent and comprehensive fashion and the few that have done so have had limited breadth. As a result, this thesis aims to contribute to the literature in this area by adding to the depth and breadth of social cost research in Ontario and by attempting to increase the standard for consistency, transparency and comprehensiveness in such an assessment.

1.4 Methodological framework

The methodological framework used to carry out this assessment is implemented in a five step process (refer to Figure 1-1 for a visual representation). Four generation alternatives are evaluated: natural gas, wind, nuclear refurbishment and new nuclear generation. These alternatives are assumed to be the likeliest candidates to be considered in the OPA's Integrated Power System Plan.

[3] Note that "capacity expansion plan" is used interchangeably with "resource allocation plan" and "supply gap decision" throughout this thesis.

Figure 1-1: Methodological framework

Step 1	Determine which electricity generation alternatives to evaluate
Step 2	Evaluate private costs of electricity generation alternatives via LUEC analysis
Step 3	Evaluate computable external costs associated with each generation alternative
Step 4	Aggregate private and external costs for each generation alternative and apply social cost estimates to Ontario capacity planning context
Step 5	Recognize uncertainty in the base case results and employ a sensitivity analysis to mitigate uncertainty

Steps 2 through 4 are applied following from the definition of social costs. A levelized unit electricity cost (LUEC) analysis (step 2), which determines the private cost per kilowatt-hour that needs to be charged for each generation alternative such that the net present value of the annual cash flows (including the cost of capital) is set equal to zero, is used to evaluate private costs. Essentially, the LUEC is the constant price that needs to be charged over the lifetime of a generating unit in order to recover all of the private costs that are incurred. Private cost factors and planning assumptions for each generation alternative are determined by taking an average for each particular variable from the relevant data in the literature. Private cost estimates are evaluated from a public and a merchant perspective which differ in terms of the appropriate discount rate used and whether transfer payments are included (all other assumptions are held constant). The discount rate in the public scenario is based on the long-term cost of public debt, as would be the case if the government was undertaking a project. The discount rate in the merchant scenario, on the other hand, is based on the increased cost of capital that would be expected when a private firm supplies electricity to the market. In the merchant case, the discount rate is higher, reflecting time preference and increased risk. In addition, taxes are included only in the merchant perspective.

For the evaluation of external costs (step 3), the bottom-up damage cost method, which is recognized as the most effective external cost valuation method in the literature, is utilized along with “second-best” valuation methods (EC, 2005). A computable external burden assessment is used to determine the external burdens that should be evaluated for each generation alternative. This assessment is used to identify the external burdens that have sufficient data availability, monetization ability and are non-negligible relative to other external burdens for each generation alternative. For natural gas generation, climate change and premature mortality costs associated with natural gas-fired emissions are evaluated. For wind generation, premature mortality and climate change costs associated with emissions from wind turbine construction and other miscellaneous costs are estimated.[4] For nuclear generation alternatives, potentially severe accidents associated with the generating unit and health impacts associated with radioactive emissions are assessed. External costs are then quantified and monetized by adapting the most relevant external cost estimates obtained from the literature to the context of this assessment.

Once private and external costs are estimated, they are aggregated for each respective generation alternative to arrive at social costs (step four). These estimates are used to determine the capacity expansion plan to meet the forecasted supply gap at the lowest social costs. In step five, a sensitivity analysis, which tests the effect on the capacity expansion plan when several key variables are altered, is employed in an attempt to lessen some of the uncertainty associated with the findings.

1.5 Thesis outline

After this brief introduction, in Chapter Two, the research objective is elaborated on and the theory behind social costs, which are comprised of private and external costs, is discussed in relation to the concepts of efficiency and sustainability. In addition, Chapter Two introduces the main elements of the Ontario electricity system as well as the current developments that are forecasted to result in a supply gap in 2025. Chapter Three establishes the means used to derive private and external costs for each generation alternative. In addition, a literature review of previous private and external cost estimates for electricity generation alternatives in Ontario provides a benchmark to evaluate the contribution to the literature made by this thesis. The methodology governing how secondary data are to be incorporated into the assessment and how the results of the social cost assessment should be utilized to meet the supply gap are conveyed in Chapter Four. Private and external cost estimates are derived for the base case scenario in Chapter Five. Private cost estimates are evaluated from a public and a merchant perspective.

[4] For wind, miscellaneous external burdens refer to noise disturbance, visual intrusion and land use.

These estimates are aggregated for each generation alternative and used to formulate a capacity expansion plan that that exhibits the lowest social costs. The discussion in Chapter Six highlights the salient aspects of the findings and comments upon the key implications of the social cost estimates while noting the limitations of the assessment. Finally, Chapter Seven summarizes the findings, draws conclusions about the usefulness of social cost assessments in general and offers suggestions for future research that are stimulated by this thesis.

1.6 Chapter summary

In this chapter, key aspects of the social cost assessment of selected electricity generation alternatives in Ontario were introduced and the context for this thesis was presented. The following chapter provides a deeper understanding of the research objective, beginning with the theory underpinning social costs.

Chapter 2 Problem justification

2.1 Introduction

The purpose of this chapter is to justify the use of social cost assessment as an effective tool to evaluate electricity generation alternatives for supply capacity expansion in Ontario. In the first part, the economic theory behind the concept of external costs and their relationship with social costs are examined and considered within the broader context of efficiency and sustainable development. Second, the structure of the Ontario electricity system including current electricity planning policies is described and various developments in the Ontario electricity sector that are projected to result in a supply gap by 2025 are discussed. This thesis will argue that an assessment of the social costs of electricity generation alternatives can be an effective tool to assist planners in Ontario to make capacity expansion decisions that minimize such costs.

2.2 Theoretical foundations

2.2.1 Economic efficiency

Under the assumptions of the first fundamental theory of welfare economics (also known as the invisible hand theorem), the market allocates resources efficiently among competing ends. The market price adjusts so that the quantity of goods and services supplied by producers equals the quantity demanded by consumers. Demand reflects the preferences of consumers while supply reflects the opportunity cost of scarce resources used in production. The so-called price mechanism acts as a signal to market participants to conserve scarce resources. Consequently, if the supply of a resource falls, its price will increase causing consumers to reduce demand and resources to be directed to their most efficient use.

When economic efficiency is attained no one person can be made better off by a change in the allocation of resources without making at least one other person worse off - a concept termed Pareto optimality (Goodstein, 1999).[5] The economist's definition of economic efficiency implies that the market produces an allocation of resources (i.e. ecological and human) that generates the maximum benefits to society (i.e. the difference between total consumption benefits and total production costs is greatest, resulting in the maximization of social welfare) (Perman et al., 2003).[6] In other words, when economic efficiency is achieved, all the opportunities for mutually beneficial exchange have been exhausted since resources have been put to their best possible uses.

2.2.2 Assessing a re-allocation of resources in terms of efficiency

When considering a particular change in the allocation of resources relative to either the status quo or to an alternative use of resources it is often the case that some people are made better off while others are made worse off. Using the notion of Pareto optimality does not allow economists to assess whether such a change is beneficial or not, as a matter of fact. Rather, in practice, the concept of a potential Pareto improvement is often used to gauge economic efficiency. According to this criterion (also known as the Kaldor-Hicks test), if the "winners" gain enough to compensate the "losers" and both groups are better off, then the change is determined to be favourable even if the compensation is never actually performed. That is to say that a potential Pareto improvement exists if a particular decision causes the net present value of the total benefits to increase even if the so-called losers are not compensated (Field and Olewiler, 2005). However, the assessment of a potential re-allocation of resources may also entail considering how efficiency gains are distributed (i.e. whether the "losers" are actually compensated) and also how such gains are reinvested (i.e. whether the gains are then used for efficient purposes). These considerations fall within the territory of sustainable development.

[5] Pareto optimality was named after the economist Vilfredo Pareto. This definition of efficiency holds under a number of restrictions that are discussed below.
[6] According to Perman et al. (2003, p. 58), "welfare is used to refer to the social good, which in utilitarianism, and hence welfare economics, is some aggregation of individual utilities".

2.2.3 Sustainable development

In addition to efficiency, economists have examined the issue of sustainable development.[7] The most widely cited of the numerous definitions of sustainable development comes from the 1987 World Commission on Environment and Development report entitled "Our Common Future", which is more commonly referred to as the Brundtland Report. It states that, "[s]ustainable development is development that meets the needs of the present without compromising the ability of future generations to meet their own needs" (WCED, 1987). Sustainability has also been defined in more economic terms as "utility or consumption that is non-declining through time" and also in terms of ecological preservation as in "satisf[ying] minimum conditions for ecosystem resilience through time" (Perman et al., 2003 p. 86). Moreover, institutional-oriented definitions exist such as "development on which people involved have reached consensus" (de Graaf et al., 1996 cited in Perman et al., 2003).

A precise definition of sustainability is not commonly held (Perman et al., 2003). However, even if a universal definition could be agreed upon, a common interpretation on how it may be achieved or implemented would remain a matter of debate due to its ambiguous nature. Voss (2001, p. 164) notes that the definition is:

> not very specific about how we can guarantee satisfying the needs of future generations, for example with reference to the energy supply. It is both vague and open-ended and therefore leaves room for different interpretations.

A less controversial aspect of the sustainability debate is that it expresses an ethical concern for the interests of future generations. Moreover, it is also well accepted that sustainable development reflects interconnections among economic, social and ecological realms (Gibson, 2005).[8] Towards this end, sustainability is concerned not only with the maximization of human welfare in the current generation, but also with how such wealth

[7] Sustainable development is also referred to in the literature as sustainability. For the purposes of this study, the terms sustainable development and sustainability are used interchangeably (as in Gibson, 2005).
[8] Some argue that cultural, institutional and political realms are included as well (Gibson, 2005).

is distributed between individuals in the current generation and individuals in future generations (i.e. both intergenerational and intra-generational equity are important).[9]

2.2.4 Re-assessing a re-allocation of resources in terms of efficiency and sustainability

As noted above, achieving economic efficiency implies that the benefits of production and consumption to society are maximized according to the Pareto definition. However, the distribution of such benefits may be overlooked in determining whether actual efficiency has been achieved. Consequently, Burtraw et al. (in Rowe et al., 1995, p. 711) note that:

> The efficiency criterion is extremely useful for organizing information for policy makers and for providing a quantitative measure of the relative importance of competing social concerns. But the efficiency criterion does not do the whole job for us.

What is missing is the distribution element that is encompassed by the concept of sustainability with respect to assessing a particular change in the allocation of resources. Efficiency can only enlarge the pie so to speak, but sustainability is concerned with how the pie gets parcelled out in addition to its size. As a result, behaviour that is governed solely in accordance with Pareto optimality may not be consistent with sustainable development. Sustainability implies that the compensation by the "winners" to the "losers" does take place and is equitable. It also presumes that efficiency gains are reinvested in a sustainable manner.

2.2.5 Efficiency and sustainability

Sustainability is neither mutually exclusive from, nor a necessary requirement for, achieving efficiency. Similarly, economic efficiency neither ensures nor precludes sustainable development. However, resource allocations that are both efficient and sustainable should be encouraged because they clearly make society better off.

[9] However, the notion of fairness between generations becomes especially complex since the values, needs and wants of future generations cannot be known with accuracy, even if we could agree that present and future generations ought to have the same capacity to succeed.

Conversely, scenarios that are inefficient and unsustainable ought to be rejected. Market failure is a situation that produces an inefficient allocation of resources that may also be unsustainable and a particular kind of market failure – externalities – is discussed below.

2.2.6 Market failure

Under certain conditions, market forces direct resources to efficient allocations as specified by the first theorem of welfare economics. (For a list of such conditions refer to Figure 2-1.) However, market failure occurs under various scenarios in which one or more key conditions of efficiency are not met. Market failure causes the true opportunity cost and level of scarcity of a good to be inadequately reflected in the market price and therefore, resource allocations, which are based on the collective preferences of market participants, become distorted; either too much or too little is supplied to the market, resulting in a resource allocation that is inefficient and hence causing a loss in welfare to society. Moreover, such a situation may also be unsustainable if market failure is an obstacle to an equitable allocation of resources among current and future generations.

Figure 2-1: Conditions necessary for efficiency in markets to hold

• Markets exist for goods and services	• Perfect competition in markets
• Market participants have perfect information	• Private property rights are assigned and enforced
• All goods are private goods	• All utility and production functions behave as price takers[10]
• All market participants are maximizers	• No externalities are present

Source: Adapted from Perman et al. (2003, p.124)

2.2.7 Externalities

The absence of any of the conditions noted in Figure 2-1 will result in market failure. One such condition, which is a central concern of this thesis, is the presence of externalities. An externality "arises when the social or economic activities of one group

[10] A price taker is defined as "a participant in a market transaction who acts in the belief that he is unable by his own behaviour to influence the terms on which the transaction takes place" (Common, 1988, p. 79).

of persons have an impact on another group and when that impact is not fully accounted, or compensated for, by the first group" (EC, 2005, p. 9). The affected party does not participate in the decision to initiate the activity and does not receive compensation for its consequences. Externalities, as defined here, exclude pecuniary externalities, which occurs "when the actions of one economic agent affects the welfare of another through price changes" (Rabl et al. 2005, p. 13). Essentially, externalities can be considered an uncompensated by-product caused by the actions of one party that affect another party. For instance, pollution generated by manufacturers of a particular good may place a strain on an ecosystem's ability to assimilate waste, produce adverse human health impacts on the public, and may necessitate environmental remediation efforts, all of which have a cost that is not reflected in the market price that consumers pay for the good. If this continues unabated, and the actual costs of pollution, in terms of its impact on public health and the environment, are not passed on to consumers through prices, the costs of the pollution are said to be external to the market price of the good. Externalities can be positive (i.e. external benefits) or negative (i.e. external costs) and are associated with production and consumption. However, external costs tend to outweigh external benefits, which will be reflected in the focus of this thesis.[11]

2.2.8 Social costs

External costs are a subset of social costs, which are represented by the following expression (Field and Olewiler, 2005):

Social costs = private costs + external costs

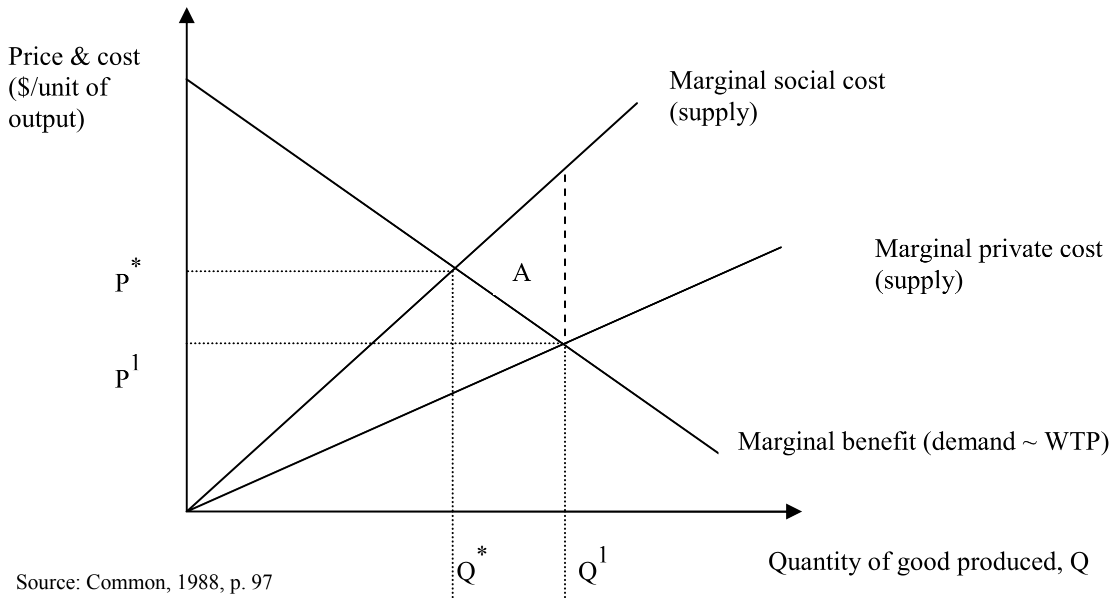
Private costs can be referred to as internalized costs, since they are passed on to consumers through the price mechanism. Conversely, external costs can be considered non-internalized damages since they are external to the price and are not passed on to consumers (ORNL & RfF, 1992). However, it is possible for an external cost to be internalized through various measures, which are discussed further below.

[11] In addition, the scope of this analysis only considers the external costs associated with production.

The following two graphs depict the effects of external costs on resource allocation. Figure 2-2 (a) illustrates the effect that external costs have on the price and the quantity of total output, while Figure 2-2 (b) shows the pollution level corresponding with the production of output. It is assumed for illustrative purposes that one unit of output generates one tonne of emissions.

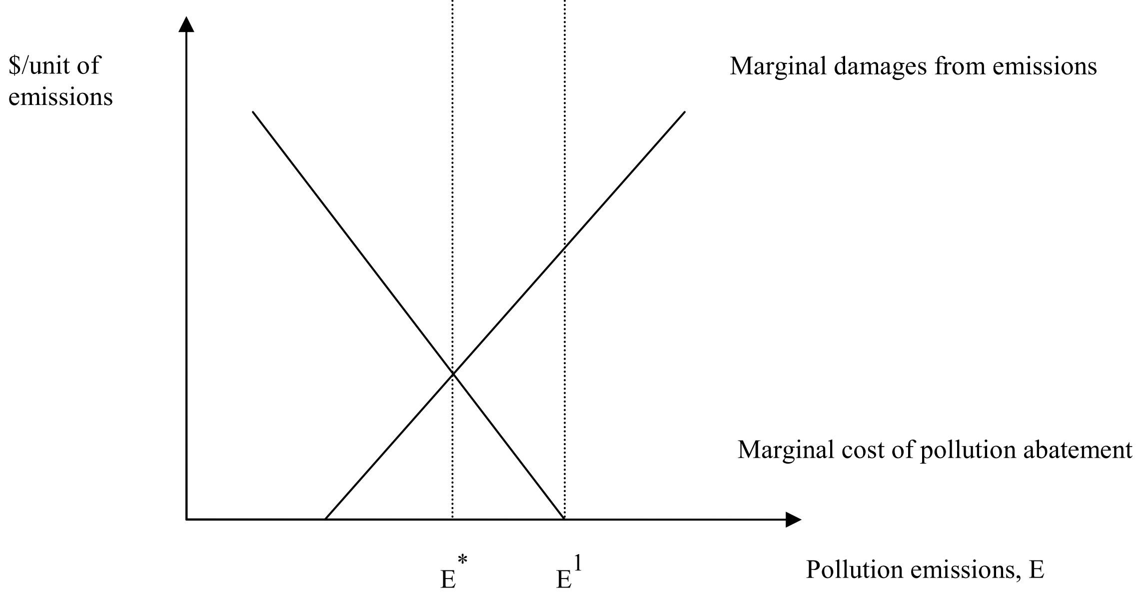
Figure 2-2: External costs of production and optimal pollution

Figure 2-2 (a) External costs of production



Source: Common, 1988, p. 97

Figure 2-2 (b) Optimal pollution level



In Figure 2-2 (a), the efficient (Pareto optimal) level of production of a good is at Q* where marginal benefits equal marginal social cost. However, in an unregulated market, producers generate output at the point where their private marginal cost is equal to demand (i.e. the consumer's marginal willingness to pay for the good, which is at Q^1). Since producers' marginal private costs are less than marginal costs to society, more quantity is produced and consumed at a lower price than what would otherwise be socially desirable (i.e. Q^1 is greater than Q^* and P^1 is greater than P^*). The external cost burden is incurred by society in general, rather than on those actually responsible for the generation of the external costs. The amount of this cost is given by area A in Figure 2-2 (a). Consequently, since external costs are, by definition, not included in the market price, resource allocation does not reflect total social costs and too many resources are devoted to the production of this good. Under this scenario, the price mechanism is an unreliable instrument to send the appropriate signal to market participants with respect to the actual opportunity cost and resource scarcity and this encourages an inefficient and unsustainable allocation of resources. Therefore, it should be evident that policies which seek to minimize private costs alone may not necessarily correlate with the Pareto efficiency and sustainability. Only when the social costs (including external costs) associated with a particular resource allocation are minimized, are resources put to their best possible use (ORNL & RfF, 1992).

2.2.9 Optimal pollution level

The degree to which external costs are internalized has a significant impact on the level of pollution that is generated. In Figure 2-2 (b), the marginal damages from emissions are assumed to increase as the level of emissions increases. In contrast, the marginal cost of pollution abatement is assumed to decline as emissions rise. With no regulation, firms could be expected to produce emissions of E^1 and spend nothing on pollution abatement, resulting in a marginal cost of abatement at E^1. If firms install pollution abatement equipment then emissions fall from E^1 and the marginal cost of pollution abatement rises. The optimal amount of pollution occurs at the point in Figure 2-2 (b) where the marginal damages of pollution and the marginal cost of pollution abatement intersect at E^*. If society were to reduce pollution to a level below this point, the costs of doing so would exceed the benefits. For example, the cost of adding an additional scrubber or sequestration device to a coal-fired electricity generation plant so that the last unit of sulphur dioxide emissions was completely eliminated would be enormous and the benefits to public health would be minimal. On the other hand, underinvestment in activities designed to abate pollution would result in the marginal damages of pollution surpassing the marginal costs of pollution abatement, leading to a net loss in welfare to society. Thus, the point where the marginal damages of pollution and the marginal cost of pollution abatement intersect is Pareto optimal and thus the net benefits to society are maximized. This intersection point corresponds to the point on Figure 2-2 (a) where marginal social costs intersect with demand at Q^*. At this point it is implied that all external costs have been internalized (i.e. at Q* marginal damages of pollution equals the marginal cost of pollution abatement).

2.2.10 <u>The relationship between external costs and property rights</u>

External costs can also be viewed as resulting from a lack of established property rights, as in the case of the so-called Tragedy of the Commons.[12] A pure common property resource is one that is non-rival, which means that one party's use of a good or service does not subtract from the amount available for others to use, and non-excludable, which means that no party can be excluded from using the good or service. Public goods, including most environmental goods and services, do not have established property rights, and are usually not traded in markets. Consequently, prices for most common property resources typically do not exist and therefore, price signals for common property resources are inaccurate in terms of accounting for scarcity and opportunity cost because they do not reflect all the costs incurred by society. This has implications for economic efficiency and sustainability since either fewer resources are available for current and future generations and/or more than the optimal level of pollution is generated than there otherwise would be if property rights were more clearly defined. Consequently, pure common property resources tend to be utilized inefficiently and unsustainably and are

[12] Property rights, which are another condition of efficiency found in Figure 2-1, are discussed here in terms of their relationship with external costs.

overexploited since private marginal costs are less than the costs incurred by society. For example, the air is commonly shared by society. Suppose it were possible to establish property rights for air and every person in society was given an equal share. Under this scenario, a person or group would not be allowed to emit air pollutants without getting permission from other owners. Presumably, owners would acquiesce to polluters' demands if they were compensated by an amount that reflected the damages imposed by the pollution. If the compensation was made, the cost of the air pollution would no longer be external and would become a private cost charged to the polluter (i.e. it would be internalized). As a case in point, this is what the policy makers who designed the tradable sulphur dioxide permit system had in mind when they introduced this mechanism to reduce sulphur dioxide emissions. Moreover, without well-defined property rights that are transferable and compulsory, the incentive for each individual to conserve resources or use them more efficiently is reduced since they would incur the cost alone and would not expect to appropriate all the benefits for themselves.[13]

Following the thread of this discussion, it is noted that not all pollution is an external cost if parties that incur the damages are sufficiently compensated, or if the polluter reduces the amount of pollution to a socially acceptable level. According to ExternE (EC, 1999a, p. 3):

> [I]f regulations or moral pressure are such as to reduce emissions by the optimal amount then there is no relevant externality…Although this may seem self-evident at one level, it has the important implication that environmental costs and externalities are not synonymous, and that measuring the former is not equivalent to identifying the latter.

Moreover, there is no further compensation requirement once internalization takes place (ORNL & RfF, 1992).

2.2.11 Internalizing external costs

Since external costs prevent resource allocations from reflecting social costs, it is desirable to design policies to neutralize their effects, a process termed internalizing the

[13] It is noted, however, that Ostrom (1990) and others have challenged this assertion.

external costs. Due to the fact that, by definition, external costs do not have market prices, they must be estimated before they can be internalized through policy instruments. With reference to Figure 2-2 (a), to internalize external costs we must determine the value of the triangle represented by A. Internalizing external costs by this amount would shift the marginal private cost curve up to the level of marginal social costs, which would achieve a price and output level that is socially optimal (at P* and Q* in Figure 2-2 (a)).

Internalization follows the objective of the polluter pays principle, which maintains that polluters ought to pay the full cost for the benefits they receive from a polluting or resource depleting activity (OECD NEA, 2003a). This point was underscored at the Earth Summit in Rio de Janeiro in 1992 by the countries attending the United Nations Conference on Environment and Development (UNCED). Principle 16 of the Rio Declaration on Environment and Development states:

> National authorities should endeavour to promote the internalization of environmental costs and the use of economic instruments, taking into account the approach that the polluter should, in principle, bear the cost of pollution, with due regard to the public interest (UNCED, 1992).

The Coase Theorem provides one method of addressing the issue of who ought to be responsible for internalizing external costs. Coase (1960) observed that as long as negotiation costs are negligible, negotiation can, in theory, resolve the problem of external costs, regardless of which party produces them. Moreover, under very restrictive conditions, it was shown that it did not matter who had the property rights – the outcome would produce an efficient result. However, the restrictive conditions outlined in the Coase theorem rarely apply in practice. When there are more than two parties, successful negotiation is rare either because bargaining breaks down, transaction costs are too high, the number of parties involved is too large, or any combination of the three (Frank and Parker, 2004, chapter 17).

Yet, the Coase theorem has broader implications for internalizing external costs. According to Frank and Parker (2004, p. 537), “the most efficient laws and social institutions are the ones that place the burden of adjustment to externalities on those who can accomplish it at least cost". Therefore, regardless of the method used to internalize external costs and regardless of who the polluter or the victim is, penalizing the parties who can resolve the problem in the least costly manner will lead to an efficient outcome.

However, while external costs are important to address, the complexity involved with quantifying such costs helps explain their pervasiveness and why they may be difficult to internalize. Internalization is straightforward in theory but in practice the procedure is more complicated. The process of identifying, quantifying and internalizing external costs is imprecise due to the uncertainties regarding external burdens and the valuation of those burdens. However, despite these limitations it may be possible to determine an appropriate order of magnitude, which is better than failing to account for external costs altogether (EC, 2005). According to Teitenberg (2000, p. 30), "an inability to monetize everything does not necessarily jeopardize the ability to reach sound policy conclusions".

In addition, critics might argue that the costs of internalization are too high, requiring a centralized accounting framework, full knowledge about the impacts and accurate decision making capability, not to mention the significant wherewithal required to coordinate and execute the entire process. The costs associated with maintaining a centralized accounting system is a valid criticism if one thinks it is necessary to monetize and internalize the external costs of every resource allocation decision. However, careful estimates of external costs for particularly significant resource allocation decisions can provide policy makers with more accurate information about opportunity costs and scarcity at a specific point in time. This can improve the ability to make more effective decisions even if a formal process of internalization is not coordinated for all market participants in perpetuity.

Another complication with properly internalizing external costs is the difficulty of determining the extent to which particular external burdens have already been partially or wholly internalized, due to the existence of various regulations or other complicating factors. This needs to be resolved before external costs are internalized through policy instruments so that policies are fair to producers and consumers (i.e. so that they are not penalized twice). In addition, distributional problems that may arise as a result of internalization must also be considered.[14]

Although a producer may voluntarily initiate the internalization of external costs on their own either for altruistic reasons or as a response to stakeholder pressure, it is more likely that internalization will be facilitated by policy measures designed to neutralize their effect. Various internalization measures exist that rely upon an estimation of external costs. Perhaps the best known example is Pigouvian taxes, whereby the magnitude of the external costs that are not reflected in the market price are estimated and charged to the producer in the form of a tax equal to the marginal external costs at the socially optimal level (Mankiw et al, 2002, chapter ten).

By internalizing the external costs of production, producers can pass the costs on to consumers through the price mechanism. This would allow social costs to be reflected in resource allocations, thereby removing a barrier to economic efficiency (Teitenberg, 2000).

However, it is noted that internalizing external costs would not automatically guarantee sustainable development. Perman et al. (2003, p. 100) maintain that

> [S]ustainability requires that market failure is corrected, but correcting market failure does not in itself ensure sustainability. Purely self-interested behaviour driven by market forces will not succeed in moving economies very far towards sustainability unless additional incentives are provided to steer that behaviour in appropriate directions.

Certainly, it must be acknowledged that internalizing external costs does not ensure sustainability. However, failing to account for external costs can be a barrier to sustainable development, which is to say that it is necessary but insufficient on its own. A number of other conditions must also be satisfied in order to achieve progress towards

[14] If external costs can be estimated, careful consideration about the appropriate internalization mechanism is necessary since the penalties may disproportionately affect a particular segment of society (e.g. people with low incomes or firms in a particular industry) or may have a negative economy-wide impact or lead to other unintended consequences. However, even if the technical obstacles can be overcome, political challenges to their implementation may be prohibitive as well (Owen, 2006). For instance, particular resource allocation decisions that are socially optimal may have an adverse impact on a particular special interest group who have the ability to influence policy decisions.

sustainable development and these may depend on the unique factors involved in each particular resource allocation decision. As ExternE maintains, external costs, which prevent total social costs from being reflected in resource allocations, are a barrier to both efficiency and sustainable development (Rabl et al., 2005).

This thesis, which assesses selected electricity generation alternatives in Ontario, identifies a preferred resource allocation plan that minimizes social costs as a method of internalizing external costs.

2.3 Social cost assessment application: Evaluating the social costs of selected electricity generation alternatives in Ontario

2.3.1 Electricity: a fundamental commodity

A reliable supply of electricity is a key contributor to human welfare and provides part of the foundation that sustains modern societies. The value of the services that electricity provides is not disputed; the blackout that affected the Northeast region of North America in 2003 served to reinforce its significance as an essential commodity. In addition to temporarily losing vital services such as cooling and lighting, this event caused a multitude of other problems that are otherwise taken for granted when the demand for electricity is sufficiently balanced by supply. Public anxiety ensued when supermarkets were forced to dispose of significant quantities of spoiled food that could not be refrigerated, disabled traffic lights caused gridlock on major roads, machinery required for the production of industrial goods was incapacitated and the threat of losing sanitation, waste disposal and water purification services forced backup generators to be activated.[15] In addition to the significant benefits of electricity utilization, it is also associated with various social costs of production that are incurred by electricity producers, the public and the environment (Holdren and Smith, 2000).

[15] Outside the boundaries of North America, it has also been demonstrated that a positive correlation exists between a minimum level of electricity consumption and human development (Reddy, 2000; Spalding-Fecher & Matibe, 2003). However, this is likely only true up to a certain threshold, after which electricity consumption and development may be decoupled. In any event, without electricity which helps to provide basic necessities such as shelter, food production, adequate sanitary conditions and healthcare, human welfare is not as likely to flourish (MIT, 2003; IEA, 2005).

2.3.2 Electricity sector in Ontario

Situated in central Canada and bounded by Manitoba and Minnesota to the West, Quebec to the East, Michigan and New York to the South and the shores of Hudson Bay and James Bay to the North, Ontario is home to 12.5 million Canadians making it the country's most populous province and largest provincial economy (Statcan, 2006). The Ontario electricity system is one of the largest in North America accounting for 28% of the total electricity consumed in Canada, which is second only to Quebec's 35% share.

In Canada, most policy decisions affecting the electricity sector are under the jurisdiction of the provinces. Whereas the federal government oversees electricity exports and international and inter-provincial power lines, the provinces and territories have control over generation, transmission and distribution within their geographical boundaries and over such matters as market structure, regulation, pricing policies and resource planning decisions (NEB, 2005).

The Ontario Government's Ministry of Energy (MOE) oversees the electricity system in Ontario by employing institutional levers to carry out its objectives. Before 1998, the government owned and operated utility, Ontario Hydro, determined which generation alternatives would make up the electricity supply mix, physically produced nearly all the electricity in the province and regulated the rates charged to consumers. However, in 1998, the Ontario *Electricity Act* reorganized the electricity sector and created a wholesale and retail market for electricity. This development also "unbundled" Ontario Hydro into three main operating units, creating a quasi-competitive market structure.[16] Ontario Power Generation (OPG) became a crown corporation responsible for providing electricity generation to the market. The firm's predominately fossil fuel, hydro and nuclear plants are still responsible for roughly 75% of current electricity generation (NEB, 2005). Hydro One became a commercial entity responsible for transmitting and distributing electricity and currently owns 97%, or roughly 29,000 km, of transmission and distribution lines throughout the province (Hydro One, 2006). The Independent

[16] In addition to these main operating units, the Ontario Electricity Financial Corporation was created to service and pay down the debt of the former Ontario Hydro and the Electrical Safety Authority was created to maintain safety standards for wiring installations and to certify equipment and appliances.

Electricity System Operator (IESO) became a non-profit organization responsible for ensuring the short-term reliability of the province's electricity system by coordinating the flow of electricity between market participants, facilitating the activities of the wholesale electricity market and by producing short -term demand forecasts.

Along with Alberta, Ontario is currently furthest along among Canadian provinces in terms of moving towards a competitive market environment (NEB, 2005). After beginning the restructuring process in the late 1990's, the wholesale and retail market was officially launched in Ontario on May 1, 2002. However, in November 2002, the government placed a ceiling on electricity prices for various consumers and restricted rates for transmission and distribution due to the increased price and volatility that occurred after the market was launched (Thomas, 2004).

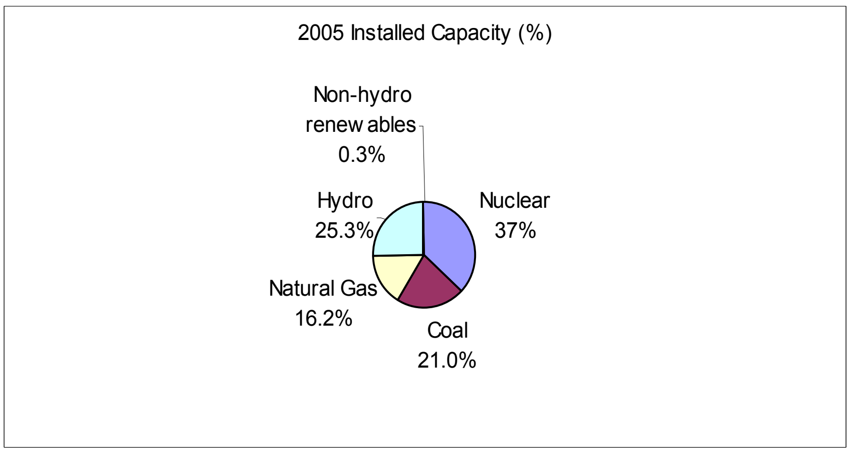
Subsequently, it was acknowledged that the sector required a more coordinated medium and long-term capacity planning function as well as stronger incentives to undertake conservation efforts (OPA, 2005). This led to the 2004 Ontario *Electricity Restructuring Act* (Bill 100), which codified various initiatives on the province's resource planning agenda and created the Ontario Power Authority (OPA) to implement them. The 2004 *Electricity Restructuring Act* charged the Ontario Power Authority with conducting "independent planning for electricity generation, demand management, conservation and transmission and develop integrated power system plans for Ontario" (*Electricity Restructuring Act*, 2004 section 25.2(1)(b)). At present, capacity expansion decisions are made by the Ministry of Energy with the assistance of the Ontario Power Authority.[17]

[17] However, independent power producers can also make their own capacity decisions unilaterally, but this is not expected to significantly alter the actual supply mix weightings relative to the Ministry's targets due to long-term supply contracts and other incentives that the government is able to provide to preferred means of generation.

2.3.2.1 Ontario supply mix

Ontario has 30,662 MW of installed generation capacity available (OPA, 2005).[18] The majority of the supply mix consists of nuclear, large-scale hydroelectric and coal-fired generation, as illustrated in Figure 2-3. Combined, these account for more than 80% of total installed generation capacity, while less than 1% of installed capacity is currently allocated to renewable sources that are not large-scale hydroelectric (OPA, 2005).

Figure 2-3: Ontario installed generation capacity in 2005



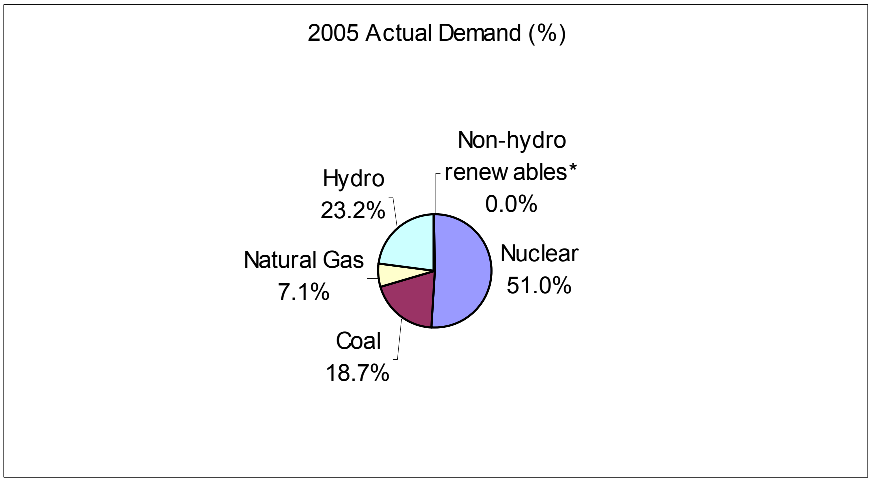
source: OPA (2005)

2.3.2.2 Wholesale electricity market in Ontario

Based on the available pool of installed supply capacity, the wholesale market facilitates the allocation of resources via the price mechanism to meet electricity demand requirements. Due to market processes (e.g. how often each generation facility is used due to plant outages, load-following ability, fluctuating demand, etc.), the actual proportion of electricity generated by each supply alternative is somewhat different than its share of installed generation capacity, as depicted by actual demand in Ontario in 2005 in Figure 2-4.

[18] As of December 2005.

Figure 2-4: Ontario actual consumption in 2005



source: OPA (2005)

* while greater than 0.0%, the share is less than 0.05% for non-hydro renewables

The wholesale price is determined by a bidding process that is driven by supply and demand. Ontario Power Generation and other electricity producers offer to supply different quantities of electricity to the market at a competitive price.[19] For each individual producer, this price is an expression of their private costs (i.e. capital expenditures, fuel costs, operations and maintenance costs, etc.) plus a profit margin. Consequently, the private cost of each generation alternative supplied to the market is different due to its cost structure in general, and due to individual producers' private costs of bringing the generation alternative to market, in particular. Simultaneously, several large electricity consumers offer to purchase different amounts of electricity at different prices. Using supply and demand information, the IESO selects the lowest priced offers until a sufficient amount of supply is available to meet demand. All electricity producers selected for generation are paid the rate of the last accepted offer (i.e. the price of the highest offer that is accepted), regardless of their original bid. This wholesale rate is used

[19] However, revenue constraints on Ontario Power Generation are in effect during the current phase of market restructuring, ensuring that OPG earns less than a competitive rate on the majority of its generation assets. The rate that OPG is allowed to submit to the market is currently fixed and depends on the generation source, e.g. 3.3 cents/kWh for large-scale hydro, 4.95 cents/kWh for nuclear and 4.6 – 4.8 cents/kWh for natural gas, coal, oil and small-hydro (NEB, 2005). These fixed rates will be lifted in phases ending in 2008 when OPG is scheduled to charge a competitive rate for all its generation assets. In addition, producers that supply the market through the "Request for Proposal" process receive guarantees that act as a price floor, but are expected to be able to increase their profitability by participating in the market.

to determine the Hourly Ontario Energy Price (HOEP), by averaging the price set every five minutes over a full hour, and it is this HOEP price that wholesale consumers are charged (IESO, 2006a). Large consumers who use at least 250,000 kilowatt-hours (kWh) per year pay this wholesale market rate. Designated consumers[20] and other consumers who fall below this threshold pay regulated rates. In addition, customers who enter into a contract with an electricity distribution company pay retail rates (IESO, 2006a).[21]

The wholesale price fluctuates often in the short term to reflect incremental changes in demand and supply. Just as the level of demand is instrumental to determining the wholesale price of electricity, the time when it is demanded is also significant. In periods of increased demand, known as on-peak periods, more expensive offers from producers must be accepted, raising the wholesale price of electricity. Conversely, when demand is low the more expensive offers are not required, keeping the price low. In the short term, demand is affected by a number of variables such as seasonal variations and time-of-day consumption patterns. Demand is normally lower in the spring and fall and higher in the summer and winter, with overall peak demand occurring in the summer and highest average demand in the winter. Over the course of a day demand varies depending on the day and the season (IESO, 2006a).[22]

Similarly, on the supply side, the amount of supply capacity available is as important as the type of generation alternative available for determining cost. In periods where either scheduled or unscheduled producer outages cause a tightening of supply, the price of electricity rises as a result. This is because as demand goes up, generation alternatives

[20] For example, municipalities, schools, universities, hospitals and farmers.
[21] Large consumers equipped with an interval meter pay the fluctuating wholesale rate, which was $0.072 per kWh on average in 2005 (without rebates) (IESO, 2006b). However, some large consumers who are not equipped with an interval meter pay the average hourly wholesale price of electricity weighted by demand in their region. According to the IESO (2006b), there are approximately 55,000 business and industrial consumers who use more 250,000 kWh/year and are thus exposed to the wholesale market rate. This segment is responsible for roughly 54% of the province's total consumption and the remainder consists of small business, residential and designated consumers who pay regulated or retail rates, which are discussed in Appendix B.
[22] In the summer, it is usually highest on weekday late afternoons and early evenings and in the winter it is usually highest in the morning and evening. In general, it is lower on weekends and holidays than on weekdays (IESO, 2006a).

with the lowest private costs are exhausted first and the more expensive generation alternatives are required to set the wholesale market price.

Regardless of whether Ontario consumers pay wholesale rates or not, their bill consists of four components: electricity generation costs which account for approximately 50% of an average monthly bill, delivery costs (i.e. transmission and distribution costs), regulatory costs(i.e. the cost of services required to operate the electricity system and wholesale market) and a charge for debt retirement (i.e. the cost of paying down the debt of the former Ontario Hydro). None of these charges reflects the total social costsof electricity generation.[23]

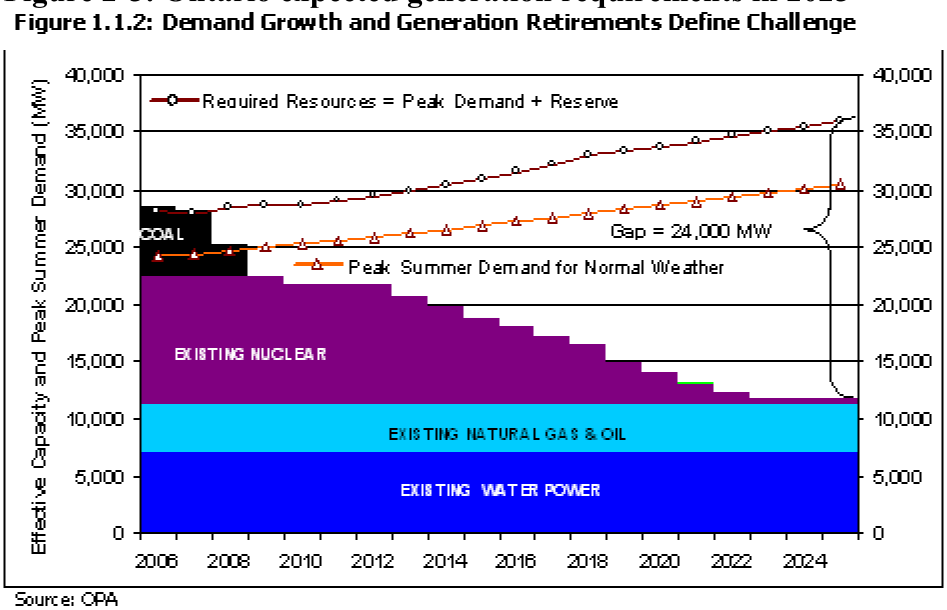
2.3.2.3 Current developments in the Ontario electricity system

Ontario is currently in the midst of a pivotal phase in the evolution of its electricity system. Although currently installed generation capacity of roughly 30,700 MW will be sufficient to meet short-term demand, various developments are underway to reshape the way electricity is generated in Ontario in the future. Citing health and environmental concerns, the Government of Ontario has stated its intention to close the four remaining coal-fired electricity generating facilities, representing a loss of approximately 6,500 MW of installed capacity, or roughly 21% of the electricity supply mix.[24] Furthermore, over the next 20 years, 10,900 MW, or roughly 95% of Ontario's aging nuclear capacity will steadily go offline as well.[25] These units will either have to be refurbished, replaced or retired. At the same time, the OPA forecasts that peak summer demand under normal weather conditions will rise by 1.3% from 24,200 in 2005 to 30,400 MW in 2025, while average demand is expected to rise by 0.9% from 155 terawatt-hours (TWh) to 185 TWh

[23] It is noted that the scope of this thesis is confined to electricity generation costs only.
[24] The Ministry of Energy determined that its proposal to close the four remaining coal-fired generators by 2009 is not feasible. Two facilities (Atikokan and Thunder) are expected to be taken offline by 2009, whereas the decision on closure dates for Lambton and Nantikoke generating units has been transferred to the Ontario Power Authority and as of September, 2006, the revised closure date remains unknown (MOE, 2006a).
[25] For a projected schedule of dates when nuclear units are eligible to go offline between 2006 and 2025, refer to OPA (2005, section 1-2, p. 17).

over the same period (OPA, 2005).[26] In sum, according to OPA (2005), it is estimated that the province will need to have approximately 36,000 MW of installed capacity by 2025 to meet demand requirements (as illustrated in Figure 2-5).[27] Therefore, over the next 20 years it is estimated that 24,000 MW of electricity generating capacity will be required on top of the approximately 12,000 MW of existing capacity expected to be still available in 2025, which represents a turnover of current capacity of roughly 80%, at an estimated private cost of $56 to $88 billion (OPA, 2005).

Figure 2-5: Ontario expected generation requirements in 2025



source: OPA (2005)

These developments pose a significant challenge for Ontario to meet its electricity supply requirements over the next 20 years. In the words of the IESO, "[t]his transition represents the largest and most significant electricity system change ever undertaken in

[26] The level of required resources is uncertain due to an inherently uncertain future demand level. Different scenarios demonstrate that demand could be anywhere from 170 TWh to 198 TWh in 2025 depending on the actual growth rate (OPA, 2005). While some analysts (e.g. Gibbons, 2006; Winfield et al., 2006) maintain that the OPA's demand projections are unrealistically high, the OPA base case scenario is considered an acceptable starting point for the purpose of this assessment.

[27] This level of demand in 2025 is an estimate of the OPA and is not fixed. It includes an 18% planning reserve in case of system outages and/or higher than expected demand. Under different planning assumptions the level of demand may be higher or lower, but for the purposes of this analysis it is considered reasonable.

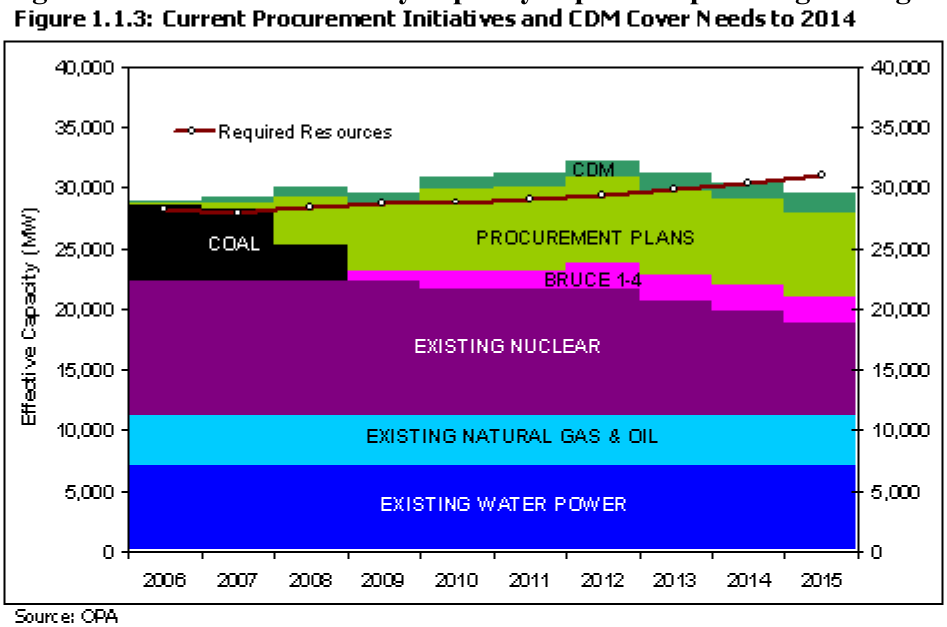
Ontario" (IESO, 2005, p. v). Due to the long-term nature of electricity resource planning and the significant lead times associated with the construction of power plants, decisions regarding capacity expansion and demand management are required over the short to medium-term.

2.3.2.4 Planned commitments

Approximately 11,000 MW of new supply capacity has been procured or planned and is projected to come online by 2010.[28] These projects include increasing natural gas capacity (6,000 MW), refurbishing nuclear units (3,000 MW), adding wind capacity (1,400 MW), conservation and demand-side management (CDM) initiatives (460 MW) and obtaining the remainder of the 11,000 MW from non-large-scale-hydroelectric renewable sources. Therefore, including these planned commitments and the 12,000 MW of currently installed capacity expected to be available in 2025, approximately 23,000 MW of the required 36,000 MW are expected to be available in 2025. Without adding any further supply capacity or reducing demand through conservation and demand-side management (CDM), the province faces a supply shortfall by 2014, which will reach approximately 13,000 MW by 2025. Figure 2-6 illustrates the plan to meet demand through 2014.

[28] Realization of these procurements is not guaranteed, but it is reasonable to assume at this point in time that they will be achieved.

Figure 2-6: Ontario electricity capacity expansion planning through 2014



source: OPA (2005)

2.3.3 <u>At issue: How to meet the supply gap in 2025?</u>

Critical decisions on how Ontario is to meet demand requirements beginning in 2014 are in the process of being taken. Winfield et al. (2004, p. 46) note that:

> Ontario is now at a critical juncture in terms of its future energy path, and that the decisions made about electricity policy over the next year will set the province's course for the next 20 or 30 years. The choices the province makes will have major implications for the health, environment, safety, and security of Ontario residents, and the competitiveness of Ontario's businesses and industries for decades to come.

Towards this end, the Ministry of Energy announced that approximately 6,000 MW of the expected supply gap in 2025 should be met by conservation and demand-side management.[29] Therefore by 2025, the gap between projected demand and forecasted supply is estimated to be roughly 7,000 MW, as represented by Figure 2-7.

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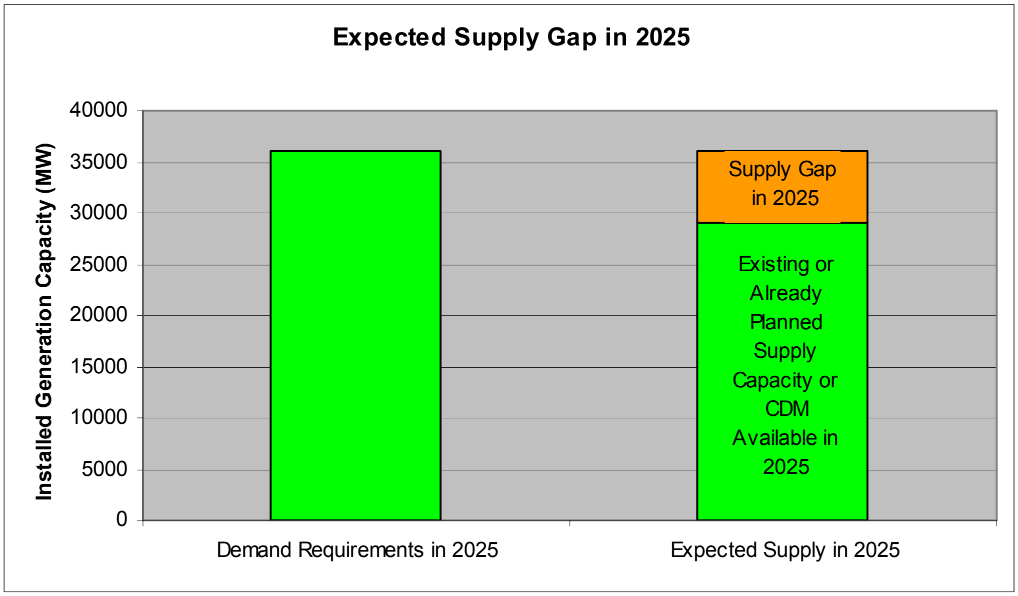
[29] This is the net total of the government's previously stated CDM target of reducing peak demand by 5% or 1,350 MW by 2007 and reducing consumption from government operations by 10% (OPA, 2005). In addition, the government is pursuing a target of non-large-scale hydro renewable sources of 5%, or 1,350 MW, by 2007 and 10%, or 2,700 MW, by 2010 (NEB, 2005).

Figure 2-7: Ontario expected supply gap in 2025



The OPA is currently in the process of compiling a 20-year Integrated Power System Plan (IPSP), which will be Ontario's first such plan since 1989 (OPA, 2006).[30] The IPSP will evaluate various generation alternatives to determine the best course of action for meeting future demand requirements over the next two decades.[31] Once completed, the IPSP will be submitted to the Ontario Energy Board for approval in early 2007. It is crucial then, at this juncture, that electricity planners at the OPA are equipped with the most accurate information and the most effective assessment tools so that they have the ability to make well-informed capacity planning decisions as to how the 7,000 MW supply gap in 2025 should beaddressed .

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[30] The Integrated Power System Plan will be based on the Ministry of Energy's response to the OPA's Supply Mix Advice Report (2005). The Ministry of Energy displayed broad support for the findings of OPA (2005), most notably agreeing that nuclear-fired electricity generation should continue to supply roughly 50% of the supply mix in 2025, that the amount of non-large scale hydro renewables should be doubled from already planned commitments and that additional natural gas capacity should not be added beyond already planned commitments. MOE also increased the target for CDM to roughly 6,000 MW, as noted earlier (MOE, 2006a).

[31] In addition, it will also consider transmission requirements, which is not within the scope of this assessment.

2.3.4 What is at stake?

The supply gap will need to be filled with one or more generation alternatives that have varying degrees of private and external costs. In order to allocate resources efficiently and sustainably, planners should aim to expand capacity with generation alternatives that have the lowest social costs. If capacity expansion is undertaken such that generation alternatives included do not have the lowest social costs, the consequences will be significant.[32] In such a situation, electricity consumption would be higher than the socially desirable level. As a result, this would undermine conservation and demand-side management efforts. Another difficulty that would arise is that the external burdens associated with electricity generation would be distributed unfairly throughout society. This is because, by definition, producers do not pass on external costs to consumers through the price mechanism. By default, the general public would be left to assume the brunt of the external costs. Moreover, the distribution of these costs would not be related to electricity consumption patterns, meaning that large consumers would effectively be subsidized by those who consume less. If it could be shown that the external costs associated with the generation alternatives used for capacity expansion are of such a magnitude that the capacity expansion decision should be altered, then that capacity expansion would be inefficient and unsustainable. In any event, due to the low turnover of generating units, Ontarians will have to live with the decision for decades to come.

2.3.5 Current criteria for assessing capacity expansion alternatives

In Ontario, capacity planning is based on three main factors: maintaining reliable supply, minimizing private costs, and mitigating health and environmental impacts associated with electricity generation (NEB, 2005).[33] This approach is consistent with the so-called

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[32] In the event that social costs are not minimized by a resource allocation for capacity expansion, it is assumed that this would be due to uninternalized external costs. Alternatively, it may also be plausible for a scenario to occur in which social costs are not minimized as a result of selecting the generation alternatives whose private costs are higher than the socially optimal level. However, this seems highly unlikely (NEB, 2006).

[33] Presumably, another factor - political objectives – can also influence the decision-making process and may serve to disrupt the desired balance. According to Field and Olewiler (2005), "Environmental policy decisions come out of the political process, where, at least in democratic systems, people and groups come together and contend for influence and control, and where interests collide, coalitions shift, and biases

integrated resource planning approach, a method used to balance the competing interests of electricity sector stakeholders to evaluate supply and demand-side management alternatives, which has been adopted in several North American jurisdictions (Spalding-Fecher and Matibe, 2003) Although capacity planning in Ontario aims to balance all three objectives it is acknowledged that the first priority is maintaining the reliability of supply (OPA, 2005). Each of these factors is discussed.

2.3.5.1 Reliability

Electricity is a unique commodity because it cannot be cost-effectively stored and as a result, supply must always be greater than or equal to demand.[34] According to the OPA (2005, section 3-3, p. 36):

> One of the most noteworthy things about the loads in Ontario is the public expectation, if not demand, that the supply of electricity be reliable. Moreover, the Ontario Market Rules specify this as a requirement and it is also a requirement of standards set by the North American Electricity Reliability Council (NERC) and the Northeast Power Coordinating Council (NPCC), in both of which Ontario is an active participant. This factor has become so engrained in our daily life that most Ontarians and Ontario businesses would have difficulty getting along without power for long, as demonstrated during the blackout in 2003.

Therefore, supply capacity in Ontario is designed to exceed forecasted demand with an operating reserve of 18% (OPA, 2005).

Electricity planners are concerned with a number of variables that could affect the reliability of supply in selecting the composition of the electricity supply mix. Generation alternatives may have base-load generation characteristics (i.e. generating units that run 24 hours a day and are able to meet demand requirements when it is low), peak-load generating characteristics (i.e. generating units that are active when demand is highest) and intermediate generating characteristics (i.e. generating units that can adjust to daily load swings less quickly than peak-load generation). For planning purposes, peak-load and intermediate generation can be lumped together in terms of their operational

intrude, Policies that emerge from a process like this may bear little relationship to what we might think of as efficient approaches to particular environmental problems" (Field and Olewiler, 2005, p. 22).

[34] If there is not enough supply to meet demand at the exact moment it is needed, consumption brownouts or a blackout can occur.

flexibility (OPA, 2005). In addition, several renewable sources do not display any of these properties and are simply referred to as "available generation" (i.e. generation output is unpredictable in the very short run). Each generation alternative has different characteristics and some are capable of providing either base-load or peaking/intermediate generation. Nuclear, coal, large-scale hydro and combined-cycle natural gas are considered to be adequate base-load options. Large-scale hydro, coal and single-cycle natural gas can be utilized for peaking/intermediate (IESO, 2005). In general, base-load generation has higher fixed costs and lower variable costs than peaking/intermediate generation. Peaking generation units produce electricity at a higher marginal cost than base-load units but are generally cheaper to construct.

Resource planning entails that the supply mix be comprised of generation alternatives that exhibit sufficient base-load and peaking/intermediate generation characteristics depending on the nature of the system's demand requirements. Having insufficient base-load generation capacity requires the use of more expensive peak-load capacity more often, raising the price of electricity. Alternatively, having too much base-load generation runs the risk of exceeding demand, resulting in generating units that are producing electricity unnecessarily, which is inefficient and costly. In addition to these cost concerns, a sufficient level of generation must have load-following capability, which is the flexibility to ramp up and down quickly to match rising and falling daily demand – a characteristic of peaking/intermediate generation. An analysis of Ontario's load duration curve by the OPA suggests that 63% of generation should be allocated for base-load generation in Ontario, with peaking/intermediate generation making up the balance (OPA, 2005).

The operating lifetime associated with power plants is another relevant factor that must be taken into consideration. In addition, planners must consider the potential likelihood of supply disruption for each generation alternative in the supply mix. Some renewable sources such as wind power exhibit intermittent generation. Other generation alternatives may be exposed to resource availability concerns or at least fuel price volatility. Moreover, the expected performance of a particular generation technology (i.e. with respect to non-planned outages) is another key consideration. Capacity planning decisions must also account for the expected risks of accidents associated with each generation alternative, which may include the risk of a catastrophic disaster. A number of technical issues also factor into reliability concerns.[35] It is recognized that maintaining a diverse supply mix provides the increased ability to mitigate or adapt to some of these reliability concerns (IESO, 2005).

2.3.5.2 Affordability

Besides maintaining reliability, minimizing the private costs associated with electricity generation is a significant consideration in selecting the optimal supply mix (*Electricity Restructuring Act*, 2004). An increase in the price of electricity can have an adverse effect on household budgets and on the competitiveness of Ontario businesses that face competition from firms in other electricity jurisdictions. This could produce macroeconomic impacts in terms of unfavourable effects on GDP and employment (van Horen, 1996). It is also likely that rate increases will be politically unfavourable. According to the NEB (2005, p. 82), "[s]ince electricity is often perceived by consumers to be an essential service, there is a political motivation to ensure entitlement to electricity at acceptable prices through regulation".

2.3.5.3 Environmental and social considerations

Policy makers also weigh environmental and social considerations into planning decisions. Pollution associated with electricity generation can be significant and can be released as solid waste, water pollution or atmospheric emissions. The impact on human health and the environment depends on a number of factors including whether abatement technology is used, the extent to which abatement is effective in reducing pollution and the proximity to those who are impacted by the pollution.

[35] These include load balancing, automatic generation control, frequency control, voltage support and black start, possibility of transmission upgrades and sufficient operating reserve (OPA, 2005).

Generation alternatives must be in accordance with regulations and have the necessary licenses that mitigate or avoid some environmental and social impacts.[36] New electricity generation projects in Ontario may be subject to the Ontario *Environmental Protection Act* and the *Ontario Water Resources Act* and the Canadian *Environmental Assessment Act* where applicable. These "are intended to provide for the protection, conservation and wise management of Ontario's environment" (OPA, 2005, section 3-2, p. 22).[37] For instance, all operations in the Canadian nuclear industry must be in accordance with Canadian Nuclear Safety Commission (CNSC), which provides health and safety standards for radiological protection (IAEA, 2003).

2.3.6 Social cost assessment

Unfortunately, there is not one particular generation alternative that provides a panacea. According to the OPA (2005, section, 1-2, p. 29):

> Planning supply mix would be simple if a single resource were superior to others in all areas – environmental impact, reliability and costs – and could meet equally well the needs of base, intermediate and peak load. The reality is that no such single resource exists – a combination of resources and technologies is needed, and tradeoffs and synergies among them must be considered.

Clearly, an evaluation that involves the consideration of such diverse impacts is difficult, especially since there is no common basis with which to evaluate the trade-offs. For example, comparing different electricity generation options entails measuring the private costs of each generation alternative and, for instance, measuring the risk of a potential

[36] However, this does not necessarily ensure that external costs are fully internalized. It is unlikely that these mechanisms, which partially reduce the total amount of external costs, are able to completely offset the external impacts of electricity generation (Roth and Ambs, 2004). For example, the number of smog days in Ontario has increased steadily over the past number of years, which implies that the optimal level of pollution is not being achieved (DSS for OMA, 2005). If regulations were able to completely internalize external costs, this would imply that regulators have a complete understanding about the impacts of pollution and also have the ability to set pollution abatement requirements that society deems optimal. According to Roth and Ambs (2004, p.2), "the ability of these political mechanisms to reflect the real benefits to society of clean and efficient power generation and to appropriately influence resource-planning decisions is questionable". Furthermore, some regulations are outdated and may not reflect the preferences of current society; they may not consider or have the ability to account for cumulative effects; they may not regulate all pollutants; they may be associated with lapses in enforcement; and some may rely on other ethical foundations in addition to economic welfare theory.

[37] However, ExternE (EC, 2005) notes that environmental assessments are focused on localized risks and may not capture the complete picture of potential impacts.

nuclear accident, the potential impacts associated with greenhouse gas emissions of wind turbine construction and the premature mortality costs attributed to atmospheric pollutants emitted by natural gas-fired electricity generation (among other external burdens for each generation alternative). Since each generation alternative exhibits disparate degrees of private costs and external burdens, it is desirable, then, to express all the relevant characteristics using common units. According to SCS (2005, p. i), there is a "growing recognition of the need for a uniform, transparent method of assessment that supports fair evaluations and comparisons among all of the electricity generation options to be considered".

Therefore, any tool that can help measure the trade-offs of generation options can assist with selecting a resource allocation that minimizes social costs. An explicit social cost assessment, in which private and external costs are estimated and aggregated, is one such assessment that can be used to identify a preferred resource allocation to meet the supply gap. This kind of assessment can be a valuable tool to measure the trade-offs associated with electricity generation alternatives because it can help to identify the relative attractiveness of each option and can assist with minimizing distortions that may be "throwing off the balancing effort". It can also help mitigate poor judgement or political interferences if carried out in a consistent, transparent and comprehensive fashion (as advocated by EC, 2005). This would limit "cherry picking" of diverse trade-offs and increase the likelihood social costs are minimized.[38] Without explicitly measuring external impacts, capacity planning decisions may incorrectly weight the pros or cons associated with a particular generation alternative, which could result in an inefficient and unsustainable use of resources.

While one of several units could be used to assess trade-offs, using monetary units can provide a deeper understanding of the advantages and disadvantages associated with each generation alternative, which could improve the ability to rank alternatives for capacity

[38] Of course, the assumptions used to monetize external costs can also be "cherry picked", but at least if the assessment is carried out in transparent fashion, the assumptions can be scrutinized by critics.

expansion based on the lowest social costs. According to Bernow and Marron (1990, p. 1):

> [T]he use of monetized values allows for clear and understandable comparisons to be made between direct economic costs (e.g., fuel costs) and environmental costs. If these costs of energy planning are not expressed in common units, comparisons become confused and the tradeoffs between economics and environment may become less comprehensible. Second, and more important, monetization allows for the consistent treatment and evaluation of environmental issues in a manner that other methods do not.

In addition, the use of monetary values recognizes that policy decisions are sometimes made within an economic framework and therefore, monetary values may be more able to capture the attention of decision makers or may be able to stimulate public discourse regarding the effectiveness of a particular generation alternative.

However, valuing environmental and social impacts in dollars is viewed as being controversial by some individuals. Some, who detest the "commoditization of nature" in general, which is the notion that everything in the ecosystem, including human life, can be quantified, oppose the monetization of external impacts on ethical grounds and contend that a monetary assessment of external costs produces a loss of sacredness for those objects that are assigned monetary values (Schumacher, 1974). In particular, assigning a value to human life - brought on by air pollution, for instance - is considered objectionable since, it is argued, the value of human life ought to be infinite. Others believe that weighting systems that place unit values on burdens are more appropriate. According to the OPA (2005, section 3-2, p. 24), "[m]onetization as an approach is problematic because it entails significant value judgements regarding the worth of environmental services, and cannot represent things that are priceless". It is suggested that quantifying burdens in units or by a qualitative assessment is preferable.

In response, *The Economist* (2005) notes that:

> As the critics allege, cost-benefit analysis works like a kind of universal solvent. It breaks qualities down into quantities, differences of kind into differences of degree, gold into base metal. A safe childhood, a breathtaking view, a clean pair of lungs – all are reduced to fungible 'dollar-equivalents'. In doing so, the method forces into the open trade-offs that many would rather not face too squarely…Such comparisons may seem crass. But they are democratic.

Proponents point out that, in reality, we tacitly accept monetary valuations in exchange for external impacts such as premature mortality risk everyday. For example, most people accept the rationality of expecting payment in exchange for medication or for repairing faulty automobile brakes (*The Economist*, 2005). Each of these tasks reduces the risk of premature mortality by some amount, yet there is a cost to doing so and it is clearly not infinite. Monetizing external costs simply expresses trade-offs that are often made implicitly in an explicit fashion using monetary values. It should also be noted, however, that in terms of the costs associated with premature mortality, it is actually individuals' collective preferences towards the incremental change in risk of reducing premature mortality that is measured and not the value of human life itself.[39] According to Daly and Farley, this is practical, as long as we "remember that we are valuing human capital as an object, not human beings as subjects" (Daly and Farley, 2004, p. 407). Moreover, it is noted that there is nothing that precludes quantifying external impacts in non-monetary units or using qualitative data, which can be useful along with monetized data since more than one set of criteria may influence resource planning decisions (EC, 1999a).

2.4 Chapter summary

In this chapter, the rationale for undertaking a social cost assessment of electricity generation alternatives was presented. Due to various developments in the Ontario electricity system, a forecasted supply gap requires the province to expand supply capacity in 2025. The research objective of this thesis is to evaluate the social costs of selected generation alternatives that are candidates to be included in the capacity expansion plan to meet this supply gap. In the following chapter, the means to evaluate social costs of selected generation alternatives are introduced and the literature is reviewed.

[39] Towards this end, ExternE has introduced the term, value of prevented fatality (VPF) as a replacement for the conventionally used value of a statistical life (EC, 2005).

Chapter 3 Establishing the means to assess social costs: A review of the literature

3.1 Introduction

To carry out the social cost assessment of electricity generation alternatives, relevant secondary data from the literature are utilized. However, selecting the private and external cost data that are most appropriate for the Ontario context is difficult because cost estimates are diverse and inconsistent. This can be attributed to the variability of the underlying assumptions of private and external cost estimates (Kammen and Pacca, 2004). However, it can also be ascribed to the methodology that is used, especially with respect to deriving external cost estimates (Sundqvist, 2004). The first section of this chapter introduces the different frameworks that are used to evaluate private and external costs. This will provide a contextual background for the utilization of such frameworks in the social cost assessment undertaken in the chapters that follow. In the second part of this chapter, the emergence of external cost assessments in Ontario and elsewhere is discussed and a commentary on the need for a more comprehensive social cost assessment of electricity generation alternatives in Ontario is also presented

3.2 Private cost estimation

3.2.1 LUEC analysis

A levelized unit electricity cost analysis (LUEC) is employed to assess the marginal private costs of various electricity generation alternatives.[40] The LUEC represents the constant real (wholesale) price of electricity per kilowatt-hour that producers would need to charge in order to exactly recover all of the private costs associated with electricity generation over the operating lifetime of a generating unit at a given internal rate of return (i.e. the electricity price that is needed to set the sum of the net present value of the discounted annual cash flows equal to zero) (Ayres et al., 2004). It can be thought of as the marginal cost of supplying electricity from a particular generation alternative.

[40] LUEC is also referred to in the literature as levelized cost of energy (LCOE) analysis (for example, Roth and Ambs, 2004).

Three main private cost elements are incorporated into such an analysis: capital costs, operations and maintenance (O&M) and fuel costs. Each generation alternative exhibits a different structure of these elements.[41]

Capital costs are "[t]he amount of capital used during a particular period to acquire or improve long-term assets such as a generating unit or plant or piece of equipment" (Ayres et al., 2004, p. 64). With respect to electricity generation, this generally refers to the costs associated with the original construction and engineering or the refurbishment of a generating unit as well as safety and pollution abatement equipment, balance of plant and other infrastructure requirements, and regulatory and licensing costs. In the literature, LUEC analyses provide capital cost estimates in terms of overnight costs expressed in $/kW. Overnight capital costs can be defined as "[t]he total capital expenditures required to develop a generating plant or unit, before adding carrying charges" (Ayres et al., 2004, p. 71). Financing costs are not included in this figure and are considered separately in section 4.2.2.

Operations and maintenance costs essentially cover all the non-fuel costs that permit a generating unit to produce electricity on an annual basis. O&M costs may be fixed or variable and may include costs associated with routine maintenance, labour, marketing, insurance, accounting and legal fees, and so on.

Fuel costs refer to the commodity cost of the resource that is used to generate electricity and they also include the cost of delivery to the point where the fuel is converted into electricity (Diener, 2001). The fuel price is variable and is based on many factors that influence demand and supply for each particular fuel such as economic development and the existing size of the resource base (NRCan, 2006).

[41] In addition, a margin for profit would be included, which is inherent in the cost of capital, which is discussed separately.

Marginal costs

To determine the capacity expansion option that exhibits the lowest social costs, it is necessary to incorporate the marginal capital, fuel and O&M costs for each potential incremental generating unit added to the supply mix into the LUEC analysis. Alternatively, average costs (i.e. the average cost of an existing generation alternative in the supply mix and a capacity addition of the same fuel type) could be used. However, this would be inaccurate since the marginal cost of adding another generating unit to the supply mix is usually more than the cost of previously installed capacity. According to NEB (2006, p. 4):

> That average cost is less than marginal cost results from the tendency of generation costs to rise over time due to inflation and other factors. It also results from the fact that the capital costs of existing resources have been largely amortised, or recovered, while the capital costs of new resources have not.

Incorporating average costs into the assessment rather than marginal costs could distort the LUEC analysis. For example, the marginal costs per kWh of adding another wind farm is lower than the average cost per kWh of an existing fleet of wind turbines (including the new units) because the new turbines have recently become cheaper due to economies of scale and more standardized components (IEA, 2000).

Despite the fact that private costs are internalized and therefore have historical market prices, there may not be a consensus as to what the future marginal cost associated with a particular expenditure should be. For instance, determining the appropriate marginal fuel costs for a natural gas-fired generating unit over its operating life can be difficult since fuel costs have been volatile over the last 5-7 years and the future price cannot be predicted with accuracy (OPA, 2005). Consequently, marginal cost estimates may be conflicting in the literature. Such estimates may differ for various context specific reasons including regional cost differences such as labour and infrastructure costs; different electricity generation technologies employed; the information available when cost estimates are made; and different assumptions, interpretations and judgements about past, present and future events.

It is also noted that marginal costs may be different within each generation alternative depending on the amount of capacity added from the same fuel source. For instance, refurbishing an existing nuclear reactor is often cheaper on a per kWh basis than building a new nuclear facility. Consequently, adding new supply capacity with a particular generation alternative may only be cost effective up to a point, after which another alternative may become less expensive.

3.3 External cost estimation

External cost estimates for each generation alternative diverge in the literature for a number of reasons. As with private costs, there is variability due to site specific factors associated with each particular generating unit and the specific external effects imposed on each receptor (i.e. the affected population or ecosystem). For instance, receptors with a higher population density downwind of a generating unit should, *ceteris paribus*, be more adversely affected in absolute terms than receptors with a lower downwind population density (Rowe et al., 1995). Site specificity refers to characteristics of the generation alternative, which affect the nature and magnitude of the external burdens imposed on receptors. This may include the technology employed by the generating unit; whether pollution abatement technology is used and how effective it is in reducing pollution; the emissions profile and the source of the fuel; and so on (Roth and Ambs, 2004). Receptor specificity, on the other hand, refers to the particular susceptibility of an affected population or ecosystem to external burdens such as pollution, noise or accident risk and may involve factors such as the proximity of the ecosystem or community to the generating unit; existing pollution concentrations due to the natural background level and industrial activity; regional dispersion variables including geological and meteorological dynamics; the resiliency of affected ecosystems and people with respect to cumulative impacts; the potential existence of thresholds and irreversibility; demographic factors such as the age and health status of the population in terms of their sensitivity to health damages from pollution; and the collective preferences of the affected population towards what is deemed an acceptable level of pollution (Sundqvist, 2002).

While site and receptor specificity add another layer of complexity to deriving external cost estimates, according to Sundqvist (2004), the greater part of the variation can be attributed to several key factors: the methodological framework utilized and the fundamental underlying assumptions particular to estimating costs for each generation alternative. According to a meta-analysis of 38 previous electricity externality studies in various geographical regions conducted by Sundqvist (2004), external cost estimates for the same generation alternative have been quite varied, with the greatest variability seen among fossil fuel sources. Sundqvist indicates that receptor specificity is less important to the discrepancy in the results than researchers' decisions on methodology and assumptions. Schleisner (2000) attributes the divergence in such results to similar causes. To illustrate the relative unimportance of site and receptor specificity on external cost estimates, Schleisner (2000) performed an evaluation on one power plant in the same location using different models from two well-known electricity externality studies.[42] Holding the site and receptor constant, it was found that external cost estimates differed by a factor of five depending on the model used. Consequently, it is important to consider the results of electricity externality studies in the light of their underlying assumptions and such results should not obscure any potential bias that may underpin the derivation of the cost estimates. Towards this end, the OTA (1994, p. 9) cautions that:

> In many cases, the methods and assumptions of these studies reflect the underlying values of the analysts who conduct the studies and the groups that sponsor them. These values often lie at the heart of disagreement over the estimates of environmental costs. Understanding the technical methodology and assumptions of environmental cost studies can help to clarify the values that are at issue.

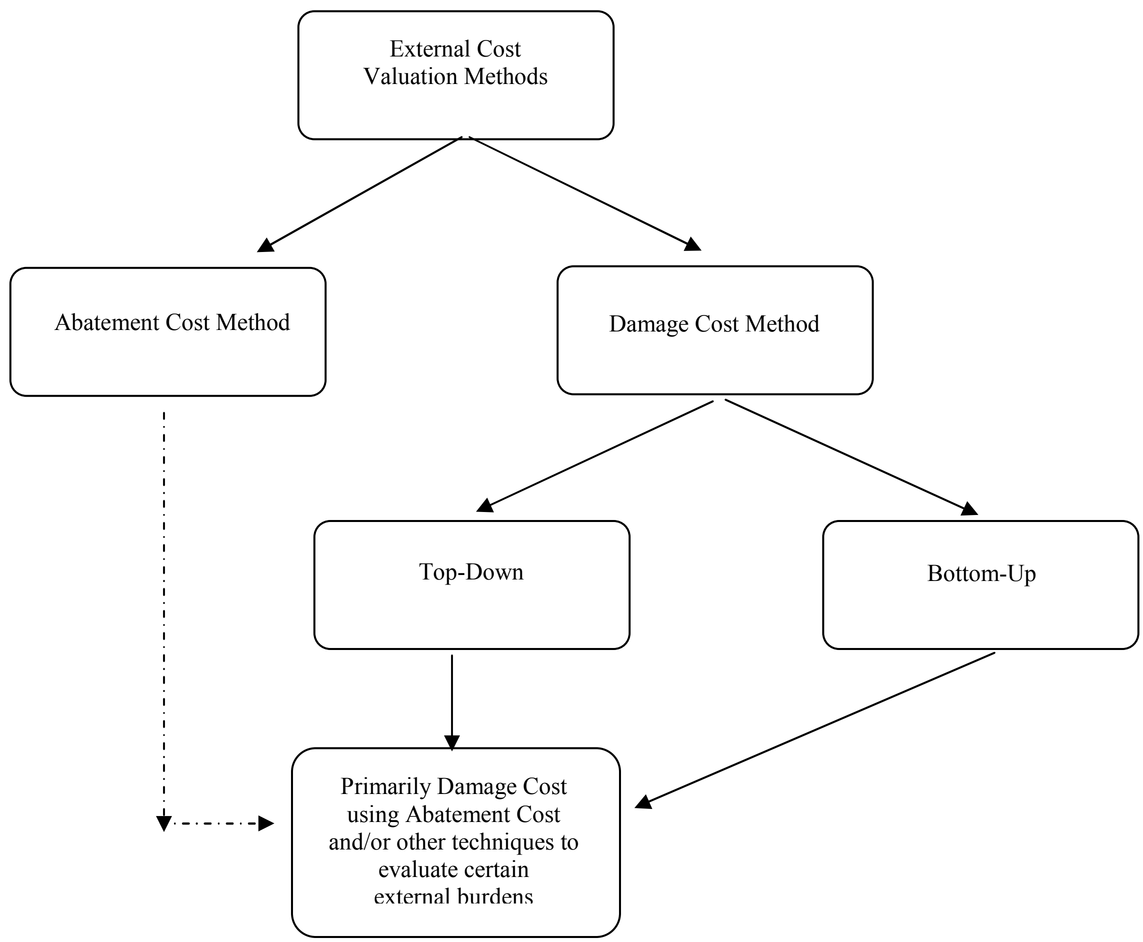
Hence, without recognizing how external cost estimates are attained, the estimates themselves are somewhat irrelevant. Rather, "[s]uch estimates become meaningful only in the context of a study's assumptions and the environmental effects that are included and excluded" (OTA, 1994, p. 72).

The literature describes two fundamental methods employed to quantify the magnitude of the external costs associated with electricity generation: the abatement cost method and

[42] The study compared the plant using the ExternE (EC, 1995) model and the Rowe et al. (1995) model.

the damage cost method, as illustrated in Figure 3-1. Practitioners of each method aim to achieve the same objective, which is to estimate the magnitude of external costs for each generation alternative. It is also noted that the abatement cost method can be used alongside the damage cost method to evaluate particular external burdens in the assessment of electricity generation alternatives.

Figure 3-1: Main methods used to quantify external costs associated with electricity generation alternatives



Source: Adapted from the text of Sundqvist (2004)

3.3.1 Abatement cost method

The abatement cost method assumes that the costs associated with controlling or mitigating external costs are a reasonable proxy for external cost estimates themselves.[43] For example, regulations may require operators of a coal-fired electricity generating plant to reduce air emissions to a certain level, obliging them to add pollution abatement equipment such as scrubbers. Proponents of this method (e.g. Bernow and Marron, 1990) argue that since pollution abatement is undertaken until the marginal benefits are equal to the marginal costs, the costs incurred by the electricity producer – as a result of the equipment installation – are representative of the external costs of electricity generation.[44] This is because at the socially optimal level of output, it is implied that all external costs are accounted for and have been internalized and, thus, the cost of pollution abatement is assumed to be of the same magnitude as the external costs associated with electricity generation. The abatement cost method is considered a revealed preference approach since its supporters suggest that regulations imposed by elected representatives are optimal and reveal the collective preferences of individuals in society. Unit costs can be derived by dividing total abatement costs by the amount of pollutant reduction achieved by abatement and is expressed in terms of dollars per unit of pollutant or emission.

A number of electricity externality studies have adopted this method to estimate external costs (for instance, Bernow and Marron, 1990; Chernick et al. 1993; and Roth and Ambs, 2004). The major benefit of such an approach is that it requires a relatively small amount of information and it is easier to implement than other methods of external cost estimation, although, accordingly, it does not provide the same level of accuracy as the other methods (Owen, 2004a).

The abatement cost method has some significant limitations. According to Sundqvist (2004), its basis in economic theory is questionable since it may not accurately represent society's true preferences. This is because it relies on the precarious assumption that regulators, who, in theory represent the collective willingness to pay of society, are able

[43] This method is also referred to in the literature as the control cost method (Owen, 2004a).
[44] A broader discussion about what constitutes the optimal level of pollution can be found in section 2.2.9.

to design regulations with full knowledge of the costs associated with pollution and the optimal degree of pollution abatement (Venema and Barg, 2003). This would imply that regulators have the ability to internalize all the external costs. However, as ExternE notes (EC, 1999a, p. 8):

> In fact it is quite clear that they do not know these costs, and the political processes by which policy decisions are made do not generally have the property that they equate social damages to costs of abatement.

Regulators may base decisions disproportionately on impacts that are incurred by special interest groups rather than on society in general (Chernick et al., 1993). According to Owen (2004a, p. 1879), the cost to society to "achieve a given standard that restricts the extent of the impact to an acceptable level…are thus likely to be only tenuously related to total damage costs". In addition, Bernow and Marron (1990) recognize that society's preferences can change over time, so even if regulations were able to produce an optimal level of pollution at some point in time, they may quickly become outdated.

Moreover, the abatement cost method implies that current regulations and policies are already optimal, which would mean that there is no need to even proceed with an assessment of external costs, since they would all be internalized already. This point is noted by the US Office of Technology Assessment (OTA, 1994, pp. 53-54), which states that:

> [Abatement cost estimates] are nonsensical because they assume precisely what they should be trying to evaluate – whether current environmental regulations are economically efficient. Because the goal of evaluating environmental costs is to balance the costs and benefits of environmental controls appropriately, they argue, then using control costs as a measure of environmental benefits entails circular reasoning. To allow balancing of costs and benefits, the estimates of these two quantities should be arrived at independently.

3.3.2 Damage cost method

Whereas the abatement cost method is used to determine the cost associated with controlling the external impacts of electricity generation, the damage cost method is used to estimate actual external burdens and to assign them a monetary cost using a valuation technique. The damage cost method can be performed in a top-down or bottom-up fashion.

3.3.2.1 Top-down damage cost method

Top-down studies estimate the external costs associated with pollution impacts that affect a particular receptor (e.g. total cost of pollution impact on Ontario) and then narrow the total costs to include only the effects caused by a particular subset that is under evaluation (e.g. costs associated with electricity generation from wind power in Ontario). To implement this method, the total emissions imposed on a receptor are obtained. Next, the emissions level of the subset being evaluated is used to determine the proportion it contributes to the total pollutant concentration. Then, a damage cost, in terms of dollars per unit of pollutant, is applied to each unit of pollutant, which is transferred from other research (Sundqvist, 2004). Two examples of studies that utilize this approach are Hohmeyer (1992) and Pearce et al. (1992).

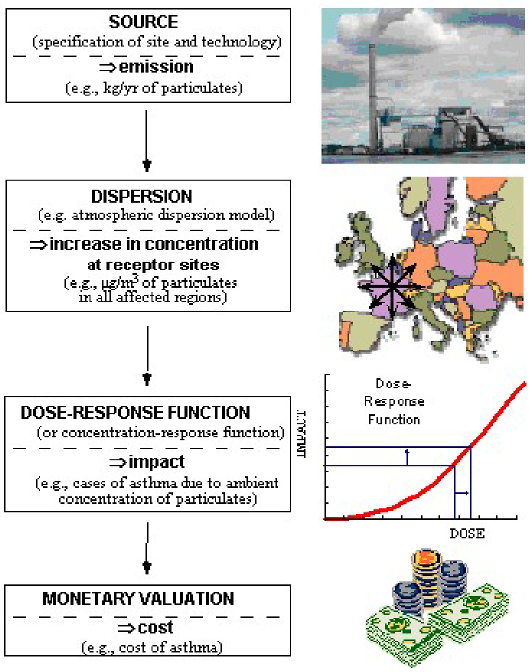
One of the benefits of the top-down method is that data from other studies can be easily transferred since aggregate figures are used (i.e. pollutant emission rates and monetary costs per unit can be applied to different receptors). Moreover, the data requirements are significantly less than the bottom-up damage cost method (Owen, 2004a). However, since this method relies on secondary data for impact and monetary valuation data, it has been criticized for not sufficiently accounting for site specific factors and for not being able to evaluate all fuel cycle impacts comprehensively (Sundqvist, 2002).

3.3.2.2 Bottom-up damage cost method

Whereas the top-down damage cost method involves attributing the total damage costs to the relevant subset of external costs under consideration, the bottom-up damage cost method directly traces the external impacts from their initial source in a systematic manner and then monetizes the impacts using valuation techniques, as illustrated in

Figure 3-1.[45] Bottom-up damage cost studies are analogous to source receptor modeling, which has its basis in the environmental toxicology literature (Venema and Barg, 2003). However, the source-receptor approach does not include applying a monetary cost to the impacts as is the case of the bottom-up damage cost method. The bottom-up damage cost method exhibits four stages: source, dispersion, dose-response function and monetary valuation, which are depicted in Figure 3-2 and explained further below.

Figure 3-2: Bottom-up damage cost method illustration



Source: European Commission, 2005

3.3.2.2.1 Source

Pollutants associated with electricity generation depend on a number of site specific factors (Roth and Ambs, 2004). In addition to the emissions generated at the power plant, various other emissions are produced in upstream or downstream processes that are required for electricity generation and should also be considered. Such upstream and downstream processes are referred to as stages in the fuel cycle. For instance, a fuel cycle

[45] In the literature this method is also referred to as the damage function approach (ORNL & RfF, 1992; Environment Canada, 1999) and the impact pathway approach (EC, 1995).

may involve exploration, extraction, processing, fuel transportation (between stages), power plant construction, electricity production, operation and maintenance, transmission, distribution, waste treatment and storage, waste disposal and decommissioning. However, each particular generation alternative exhibits its own unique set of fuel cycle stages and emissions profiles. ORNL & RfF (1992, p. ix) defines the fuel cycle as, "the series of physical and chemical processes and activities that are required to generate electricity from a specific fuel or resource".[46]

3.3.2.2.2 Dispersion

After establishing the magnitude of emissions attributable to a particular fuel cycle, the diffusion of the emissions by air, water and land is tracked across space and time. This is carried out by utilizing computer modeling analysis tools that are designed to account for a number of complexities including meteorological factors (i.e. wind speed and direction, weather patterns and dry and wet deposition processes), background pollution concentrations (including natural sources, other pollution from within the geographical boundary and transboundary emissions) and chemical interactions between pollutants (EC,1995).

3.3.2.2.3 Dose-response function

The next step in the process is to measure the impacts of the dispersed emissions on the affected receptors (in terms of health or other external effects). Relevant epidemiological, environmental, and risk assessment data are utilized to obtain dose-response functions for an affected population (e.g., an increase in lung cancer cases due to an increase in atmospheric concentration of ground level ozone) or for an affected environmental receptor (e.g., a reduction in crop yield due to increased acid deposition).[47] Dose-response functions quantitatively measure the increased risk of emissions on each

[46] A fuel cycle analysis is comparable to a life-cycle analysis, which catalogues "material and energy flows associated with all stages in the life cycle of a product or activity, from raw material production and transformation to end use and waste disposal, that is, 'from cradle to grave'" (OECD NEA, 2003a, p. 18).
[47] Dose-response functions are also referred to in the literature as concentration-response and exposure-response functions.

receptor in terms of impacts relative to baseline data (Rowe et al., 1995).[48] Dose-response functions are applied to all receptors for which data are available to determine the impacts associated with emissions. Quantifying some impacts are highly complex while others involve only a few parameters (EC, 1999b). Impacts are estimated by multiplying the number of people in an affected receptor by the increased risk of a particular health or environmental impact above the baseline data (DSS for OMA, 2005).

Bottom-up studies (for example, DSS for MOE, 2005; Rowe et al., 1995) have used regional data (census data) to determine marginal impacts from the increase in emissions on a particular receptor. The dispersion of emissions, which reflects the regional concentrations of pollutants, is measured in relation to the reference concentrations within each respective census division. Consequently, the receptor specificity objective is satisfied to the level of the census boundary (i.e. average impacts for each census division are calculated). This vicinity is considered to be small enough to capture receptor specificity differences (DSS for MOE, 2005). However, it should be noted that within each census division, variability of impacts may exist.

3.3.2.2.4 Monetary valuation

Valuation techniques are designed to measure the collective preferences of individuals in an affected population towards the tolerability of particular external impacts (since there is usually not a market price for such impacts with which to gauge individuals' preferences).[49] The value that individuals place on external impacts is directly linked to the opportunity cost of resources that could be put to a more efficient alternative use. There are a number of ways to monetize external impacts depending on what is being valued. If market prices are available they should be utilized. For example, crop yield damages can be multiplied by the market price of the commodity to determine the

[48] It is noted that dose-response functions express increased risk and the correlation between increased emissions.

[49] However, it is noted that individuals may not always govern themselves according to personal preferences (i.e. they may operate at times based on public/altruistic preferences). This implies that estimating external costs based on individuals' private preferences may not always be correct (Sundqvist, 2002). However, the restrictive assumption that people are governed solely by personal preferences holds for this assessment.

monetized external cost. However, for most external impacts market prices are not available. Consequently, two general types of valuation techniques are used: stated preference techniques (i.e. directly asking individuals to disclose their willingness to pay for a hypothetical scenario) and revealed preference techniques (i.e. inferring preferences from actual behaviour).[50]

Ideally, it is possible to directly ask individuals to express their willingness to pay (WTP) for (or to avoid) specific external impacts. In theory, WTP is an expression of individuals' preferences. Alternatively, revealed preference techniques may be utilized. For example, researchers may use purchase data of an actual good to deduce what individuals would be willing to pay to avoid a particular external burden. This technique assumes that the behaviour is consistent with utility maximization (EC, 2005). For example, researchers can measure house prices in a quiet area against prices in an area with significant noise pollution to infer individuals' willingness to pay to avoid the noise.

The most comprehensive bottom-up analysis has been the ExternE research study (EC, 1995; 1999a; 2005a, others). Other notable studies using the bottom-up damage cost method are Rowe et al. (1995) and ORNL & RfF (1998).

The bottom-up damage cost method is designed to measure the collective preferences of individuals in society so that marginal costs reflecting site and receptor specificity may be evaluated. Bottom-up studies generally provide a consistent methodological framework that "represent advances over older studies because they review a larger body of literature, they are often more systematic in their survey of emissions and environmental impacts, and several elements of their technical methodology are more sophisticated" (OTA, 1994, p. 7). Sundqvist (2004, p. 1756) states that "this is the approach that is most in line with economic theory and…is currently the most preferred approach to the assessment of the externalities in the electricity sector".

[50] For a more comprehensive analysis on various stated preference and revealed preference techniques, the reader is directed to EC (2005) section 3.3. In the interest of conciseness, only the particular stated preference and revealed preference techniques that are applicable in the context of evaluating computable external costs associated electricity generation alternatives in Ontario are described here.

However, there are a number of limitations associated with this method as well. Due to the large data requirements relative to the other methods, some impacts are not adequately accounted for (Owen, 2004b). According to Alnatheer (2006), bottom-up damage cost studies do not adequately cover all potential external impacts as a result of the lack of data availability or monetization ability for some external effects. Moreover, according to Clarke (1996):

> The bottom-up approach has been criticized since applications of the method have unveiled a tendency for only a subset of impacts to be included in assessments, focusing on areas where data is readily available and where, thus, impact pathways can easily be established. Consequently, bottom-up studies tend, it is argued, to leave out potentially important impacts where data is not readily available (quoted in Sundqvist, 2002, p. 8).

Alnatheer (2006) indicates that external cost assessment is most developed in the literature for impacts associated with air pollutants. This apparently penalizes fossil fuels, which are more closely associated with air pollution impacts, relative to nuclear and renewable generation alternatives, which are associated with other kinds of external costs

In addition, there is uncertainty associated with every step of the bottom-up process for the external costs that are quantified and monetized. Although emissions can be evaluated rather objectively, there are inherent limitations in dispersion modelling. Despite the fact that techniques for dispersion modelling have advanced in recent years, the simplified relationships developed to model complex interactions between pollutants can never precisely reproduce what goes on in reality. According to the US EPA (2003a), short-term dispersion model estimates have an error range between +/- 10 and 40 percent, which is less accurate than models that estimate long-term concentrations (cited in DSS for MOE, 2005). Moreover, dose-response functions may not be able to fully capture the complete package of impacts that could be imposed on receptors as a result of increased emissions. Various limitations are also associated with valuation techniques. Since external costs are not readily available and need to be estimated, there is an inherent element of uncertainty with respect to the estimates that are obtained using valuation techniques. Furthermore, some external burdens may not be sufficiently measurable if individuals' unfamiliarity precludes the development of their preferences towards it or if the potential impacts are too uncertain to value.

It is likely that regardless of the improvements in dispersion modeling, epidemiological research and valuation techniques, bottom-up assessments will always be unable to completely account for complexities in the real world with precise accuracy. However, even though some external effects cannot be quantified or monetized with the current state of knowledge, the bottom-up damage cost approach can still be a valuable tool to evaluate competing alternatives since it is able to provide approximate damage cost estimates, even if the figures are somewhat imprecise. And it is able to provide an appreciation of the trade-offs that are involved in an assessment of generation alternatives, even if all the external effects cannot be quantitatively assessed. Pearce (2001, p. 31) notes that:

> Uncertainty is not a reason for neglecting economic valuation – there is a widespread but erroneous view that if we avoid trying to estimate economic values what we will end up with is a more certain base for policy making than if we do not.

The fact that there are gaps and uncertainties associated with bottom-up damage cost estimates is a serious limitation, but should not be interpreted as a fatal flaw. Rather, it is hoped that future research will be able to respond to these weaknesses and reduce some of the uncertainty.

3.3.2.3 Bottom-up damage cost method supplemented with "second best" estimation methods for particular external burdens

Using a "pure" bottom-up damage cost method to estimate external costs of electricity generation would be ideal because it most accurately reflects site and receptor specificity. However, while its strength lies in estimating the external effects of atmospheric emissions, various other potentially significant impacts are incomputable with such an approach (Alnatheer, 2006). Consequently, in situations where external effects cannot be sufficiently quantified or monetized by the bottom-up damage cost method, other "second best" methods may be employed (EC, 2005, p. 4). Such methods vary depending on the external burden that is assessed (e.g. abatement cost method to evaluate climate change impacts or expected value method to assess potential nuclear accidents).

In practice, most bottom-up damage cost studies include estimates for several impacts that are not sufficiently quantifiable using the bottom-up method alone. Including other estimation techniques with the bottom-up damage cost method is favourable because it combines the best qualities of all the methods. It can produce estimates that generally reflect site and receptor specificity and it can facilitate the estimation of otherwise incomputable burdens. Of course, it also encompasses the limitations associated with the second best methods as well. However, it is argued that although the evaluation of such burdens are less precise than using the bottom-up damage cost method, the use of second best methods is better than valuing such costs as zero (Ottinger et al., 1990).

3.3.3 The emergence of electricity externality studies

The methodology used to estimate external costs of electricity generation alternatives has evolved over the last 15 to 20 years. At the same time, electricity externality studies themselves have emerged from obscurity to garner some consideration in resource planning decisions. According to Kammen and Pacca (2004, p. 302):

> Over the past few decades, the importance of hidden costs and environmental externalities in the development of energy projects has evolved, and although the methods used to monetize these values are still debated, their influence on our thinking about cost-benefit analysis for decision making is indisputable.

In the late 1980s and early 1990s, the abatement cost and top-down damage cost methods were prevalent. In the mid-1990s the bottom-up method, as practiced by ExternE (EC, 1995) in Europe and Rowe et al. (1995) and ORNL & RfF (1998) in the United States, became the benchmark for later studies that would follow a similar approach. This method produces lower estimates than the top-down or abatement cost methods partially due to the fact that they are more reflective of site and receptor specificity (Sundqvist, 2004). Currently, the bottom-up damage cost method remains the predominant framework used to estimate external costs associated with electricity generation alternatives, albeit with the support of other "second best" techniques for the evaluation of particular impacts that would otherwise be unquantifiable (EC, 2005). In particular, ExternE is considered to be the state-of-the-art for the assessment of external costs of electricity generation (Venema and Barg, 2003, EWEA, 2003; OECD NEA, 2003a). According to Sundqvist (2002, p. 13), "[t]he scientific quality of the ExternE work as well as the methodologies used has been well accepted at the international level, and many followers rely heavily on the numbers and the methods presented".

Electricity externality studies continually build on improvements to dispersion models, new epidemiological knowledge and advancements in valuation techniques. Due to the transferability of dose-response functions and valuation data, studies also build on each other. Consequently, the most recent external cost estimates utilizing the bottom-up approach can be traced back to ExternE (EC, 1995), Rowe et al. (1995) or ORNL & RfF (1998), at least to some extent.[51] This is evident by the converging orders of magnitude of monetized external cost estimates between studies (Rabl and Dreicer, 2002). However, even though estimates derived in the literature are not completely independent (i.e. they build on each other), they are still divergent enough that a consensus on cost for an assortment of particular external burdens does not exist.

Despite being accepted as the most effective framework to assess external costs with, various limitations of the bottom-up damage cost method are apparent, not least that some key impacts remain incomputable. As such, external cost estimates for electricity generation alternatives remain a work in progress. The existence of incomputable burdens, the lack of consistency in the literature for a number of external burdens (even though in general the estimates are converging somewhat) and the degree of uncertainty with respect to the computable burdens has contributed to preventing external cost estimates from being widely used in policy decisions to date (Sundqvist, 2002).[52] Furuholt (2001, p. 110) notes that:

[51] In fact, the externality research carried out by ExternE and ORNL and RfF started out as a collaborative project in 1991, when it was known as the EC/US Fuel Cycles Study (EC, 2005).
[52] In addition, the general lack of political will may also prevent such results from being extensively used for policy making.

> The work on externalities is important and interesting, but one should be very conscious of the limitations of the available methods and that they will never give objectively correct answers. The current state of the art regarding externalities of energy production and products is far from giving a complete picture, although significant progress has been made during the last decade. The results from studies of externalities should therefore never be regarded as more than one of several inputs in any decision process, whether in industry or in politics.

While, this should not imply that previous electricity externality studies have been meaningless, it does indicate the need for more rigorous consistency between methods used in external cost studies; more transparency and explanation of the methodological framework and key assumptions used by analysts to derive external costs; and the acknowledgement that external cost estimates can still be used in a complementary role even if they cannot be relied upon exclusively for policy recommendations.

3.4 Previous electricity externality research and other notable damage cost studies in Ontario

Several electricity externality studies and related externality research have been conducted in Ontario in the past. They are discussed here briefly.

3.4.1 <u>Chernick et al. (1993)</u>

Chernick et al. (1993) apply the abatement cost method to assess external costs associated with fossil fuel-based electricity generation alternatives (coal, coal with abatement cost technology, natural gas combined-cycle technology and natural gas cogeneration). In addition, nuclear-fired generation is evaluated by utilizing a primarily bottom-up damage cost method. Premature mortality costs associated with the release of radon from uranium tailings and nuclear accident risk are evaluated. However, the nuclear data in Chernick et al. (1993) are not presented transparently, making the results hard to assess. In their study, coal-fired generation was estimated to have the highest external costs among the generation alternatives evaluated.

3.4.2 Ontario Hydro (1993 - 1996)

Ontario Hydro quantified external costs associated with coal, natural gas and nuclear generation alternatives from 1993 to 1996. They used the bottom-up damage cost method to determine external costs associated with electricity generation. The purpose was to improve resource planning decisions (US EPA, 1996). The results are not available for public use.

3.4.3 Chestnut et al. (1999)

The Air Quality Valuation Model (AQVM version 3.0) is a computer model produced for Health Canada and Environment Canada to assess the health and environmental damage costs linked to air pollution (Chestnut et al., 1999). It was developed jointly by Canadian researchers and by several authors of Rowe et al. (1995). This model is based on the bottom-up damage cost method and contains baseline air quality and pollution data for all census divisions in Canada based on the National Air Pollution Survey data from 1991 to 1993 compiled by Environment Canada. It contains dose-response functions and valuations for air pollution impacts suitable for the Canadian context.

It is noted that Chestnut et al. (1999) is not original externality research. Rather, it is a computer model that has been used by several studies (e.g. Venema and Barg, 2003; DSS for MOE, 2005) to derive external cost estimates but is not currently available to the public.[53] According to Venema and Barg (2003, p. 21), "[t]he advent of AQVM established a Canadian standard for valuing the public health benefits and costs of changes in ambient air quality".

[53] The AQVM tool is no longer available to the public since a newer version – the Air Quality Benefits Assessment Tool (AQBAT) – is currently in development and its release date is unknown (Michael Donohue, personal communication, 2006).

3.4.4 Venema and Barg (2003)

Venema and Barg (2003) estimated the "full costs" of electricity generation from coal, oil and natural gas in Eastern Canada.[54] Venema and Barg obtained emissions data for electricity generation sources in Eastern Canada using the top-down damage cost method, drew on the emission dispersion modelling conducted by AMG (2000), and integrated it with data from Chestnut et al. (1999) to ascertain monetary costs for air pollution. The authors note that other stages in the fuel cycle besides electricity generation are unaccounted for.

3.4.5 DSS for OMA (2000 & 2005)

The Illness Cost of Air Pollution (ICAP) computer model is used to measure the monetized health impacts of air pollution on the province of Ontario using the bottom-up damage cost method. The latest report (DSS for OMA, 2005) refines the dispersion model, dose-response functions and valuation techniques developed in DSS for OMA (2000). It is noted that the authors of these studies also carried out DSS for MOE (2005).

3.4.6 DSS Management Consultants Inc. and RWDI Air Inc. for the Ontario Ministry of Energy (DSS for MOE, 2005)

In 2005, DSS Consultants Inc. and RWDI Air Inc. prepared an analysis for the Ontario Ministry of Energy that investigated the social costs of replacing electricity from coal-fired generation in Ontario. The assessment looked at private and external costs of coal and natural gas and the private costs associated with nuclear refurbishment. Private costs were determined in consultation with Ontario Power Generation and the Ontario Ministry of Energy. Health and environmental costs were obtained using a bottom-up methodology that used the same dose-response functions and monetary valuations as DSS for OMA (2005), due to the fact that the studies were compiled by the same consultants.

[54] Evaluation covers all provinces to the east of Manitoba (not including Manitoba)

3.5 The need for a comprehensive assessment of the social costs electricity generation alternatives in Ontario

Private costs have traditionally been and continue to be a key component in electricity resource planning decisions in Ontario (OPA, 2005). Although several recent studies have evaluated the external costs of fossil fuel sources in Ontario, a gap in the literature exists with respect to the need for a consistent, transparent and comprehensive social cost evaluation of electricity generation options. Ideally, such an assessment should reflect an unbiased estimation of private costs, taking a number of perspectives into consideration. For external cost estimation it should reflect the state-of-the-art bottom-up damage cost methodology and the most current site and receptor specific data on impacts and valuations. Moreover, it should follow down a similar path as the Ontario Hydro external cost studies from the mid-1990s and build on the external cost estimates derived by DSS for MOE (2005) for fossil fuel-fired electricity generation. In addition, it should exhibit greater breadth than previous Ontario electricity externality studies by including an evaluation of the external costs associated with nuclear power as in Chernick et al. (1993) and renewable sources.

3.6 Chapter summary

This chapter outlined the instruments that are available to assess social costs. LUEC analysis, which will be used to derive private cost estimates for each generation alternative under study, was introduced. The review of the external cost literature in the second part of this chapter revealed that employing the bottom-up damage cost method with other "second-best" methods for particular external burdens is the most effective way to estimate external costs, and this method will be utilized to evaluate external costs. The next chapter explains how these instruments will be implemented so that social cost estimates may be derived.

Chapter 4 Methodology

4.1 Introduction

This study examines various electricity generation alternatives that may be considered by resource planners for an expansion of Ontario's electricity supply capacity. To compare capacity planning alternatives, an assessment of their social costs is carried out and this chapter outlines the scope of the analysis and the methodological framework that will be used to implement the assessment. A levelized unit electricity cost (LUEC) analysis is used to evaluate private costs. Since private cost factors and planning assumptions in the literature are divergent, it is necessary to employ a consistent methodology to determine which cost figures and assumptions to use. A computable external cost assessment is undertaken to identify the external burdens for each generation alternative that are non-negligible and such burdens are quantified and monetized using the benefit transfer method. Finally, this chapter discusses how the aggregated private and external cost estimates can be used to select generation alternatives that meet electricity demand requirements at the lowest social costs and how a sensitivity analysis will be carried out.

4.2 Methodological framework

The methodological framework for this study consists of five main steps that are described in Figure 4-1. Steps 2 through 4 are applied following from the definition of social costs (refer to section 2.2.8 for the definition). The objectives described in each step are subject to various constraints, which are explained in detail below.

Figure 4-1: Methodological framework

Step 1	Determine which electricity generation alternatives to evaluate
Step 2	Evaluate private costs of electricity generation alternatives via LUEC analysis
Step 3	Evaluate computable external costs associated with each generation alternative
Step 4	Aggregate private and external costs for each generation alternative and apply social cost estimates to Ontario capacity planning context
Step 5	Recognize uncertainty in the base case results and employ a sensitivity analysis to mitigate uncertainty

4.2.1 Step 1: Determine which electricity generation alternatives to evaluate

The generation alternatives evaluated in this study are determined by selecting the main alternatives being considered by the Ontario Power Authority in its forthcoming Integrated Power System Plan. The particular technologies that are assumed to be employed for each generation alternative in the event that it is added to the supply mix are identified. These generation options are assumed to be connected to the Ontario electric transmission and distribution system.

4.2.1.1 Electricity generation alternatives considered by the OPA for capacity expansion

The Ontario Power Authority's forthcoming Integrated Power System Plan (IPSP) will provide a framework for the Ontario government to make resource planning decisions for the province's electricity system over the next two decades.[55] As part of the process culminating in the IPSP, the OPA (2005) evaluated adding generating capacity from three main supply sources: natural gas, wind and nuclear.[56] In addition, various conservation and demand-side management (CDM) initiatives were considered.[57] Coal and large-scale

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[55] Although it is possible that the government may consider supply and demand issues that pertain to the province that lie outside of the jurisdiction of the OPA, it is unlikely given the role that the OPA serves in the structure of the industry as defined by the 2004 *Electricity Restructuring Act*. Consequently, the Integrated Power System Plan, which will be based on the Ministry of Energy's response to OPA (2005), is considered to be a logical starting point for this study to determine which generation alternatives to evaluate.

[56] Out-of-province large-scale hydro capacity was also evaluated. However, its realization is considered highly uncertain at this time and therefore it does not fall within the scope of the analysis performed here. Moreover, OPA (2005) considers a smaller amount of non-large scale hydro and non-wind renewable sources that will also not be evaluated here.

[57] Many other observers maintain that policy decisions regarding the future of the Ontario electricity system should be comprised of CDM initiatives in addition to a judicious expansion of supply capacity (Elwell et al., 2002; Winfield et al., 2004; Gibbons, 2005). Some examples of CDM include load shifting encouraged by time-of-use pricing policies in conjunction with smart meters, process efficiency gains, utilizing energy efficient appliances and light bulbs, consumer education and increasing the performance of electricity distribution systems. Prudent conservation options that reduce overall demand, and electricity demand-side management strategies that lower and shift demand away from on-peak periods, should be considered first and foremost as a least cost, environmentally sound alternative to meeting demand requirements (Chernick et al., 1993). The IESO (2006a) states that, "Investments in shifting consumption to off-peak periods and reducing overall demand are more cost-effective than financing the construction of new power plants". According to NEB (2006), demand management costs between \$0 - \$0.050/kWh, which is lower than most conventional alternatives. Moreover, the OPA states that "conservation is the only way of balancing electricity demand and supply that has little or no long-term impact on the environment" (OPA, section 1-2, 2005, p. 15). These initiatives can reduce or defer the need to expand peak generation capacity and investments to the transmission and distribution grid, which can reduce price volatility and increase system

hydropower, though currently constituting a significant portion of Ontario's electricity supply mix, were not considered since the government has signalled its intention to close the four remaining coal-fired generators and since large-scale hydropower capacity in Ontario is nearly fully utilized. (OPA, 2005).

Various other potentially appealing supply sources or technological innovations are not, at least at the moment, highly prioritized by the OPA. These include, but are not limited to, off-shore wind, solar thermal, photovoltaic, small-scale hydro, biomass including landfill gas, cogeneration, geothermal, coal gasification, carbon sequestration and hydrogen and fuel cells. Renewable sources generally offer environmental benefits over conventional sources and "can contribute to a more reliable system through supply diversity, increased reliability, and predictable and generally low O&M costs" (Kammen and Pacca, 2004, p. 314). Such emerging technologies "are thought to have significant promise and increasing application over the longer term" (NEB, 2006, p. x). The potential capacity that these sources can contribute to the supply mix may be significant, but their current levels of utilization for electricity generation in Ontario and elsewhere are minor relative to the conventional sources noted above.[58] While electricity utilization from these sources may intensify in the future, they are not included in this assessment at this time.

Thus, although various conventional sources and CDM initiatives demonstrate numerous potential benefits, this study is confined to the supply-side alternatives which appear to be the most attractive to the Ontario Power Authority, namely natural gas, wind and nuclear.

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reliability (Winfield et al., 2004; Rowlands, 2005; Navigant, 2005). Yet, despite their numerous potential benefits, CDM alternatives are not assessed here. Rather, this assessment is focused solely on evaluating generation alternatives on the supply side that will allow the province to meet its long-term capacity requirements.

[58] For example, the Ontario Clean Air Alliance suggests that it is possible for renewable sources to comprise 60% of total electricity generated in Ontario by 2020 (Gibbons, 2005).

4.2.1.2 Expected technology used for capacity expansion

It is also important to identify the specific technology that is assumed for each generation alternative under evaluation. The particular technology utilized can be significant since it can have a considerable effect on a number of factors that affect marginal costs, such as capital expenditures and emissions. It is assumed that whichever the technology employed for each generation alternative, it will exhibit modern pollution abatement equipment and will be in accordance with all relevant federal and provincial environmental regulations. Each generation alternative is discussed briefly below:

4.2.1.2.1 Natural gas

Natural gas-fired electricity generation facilities may utilize single-cycle gas turbine (SCGT), combined heat and power (cogeneration) or combined-cycle gas turbine (CCGT) technology. Among these technologies, single-cycle plants are associated with greater load following capability (i.e. they can be more responsive to fluctuating demand), but are also less efficient at converting gas to electricity (OPA, 2005). At the other end of the spectrum, cogeneration plants have very limited load following capability but can achieve very high efficiencies. According to Gibbons (2006), combined heat and power plants can achieve efficiencies in the 80-90% range since they utilize a significant proportion of the heat created by the conversion of natural gas to electricity for space heating or industrial processes. However, while cogeneration facilities offer significant benefits, there has been limited adoption of this technology in Ontario and elsewhere to date, due to the lack of incentives to build them (OPA, 2005). In addition, the costs associated with cogeneration facilities will likely vary depending on the specific configuration of the project, making this technology hard to evaluate. Combined-cycle facilities, on the other hand, are standardized and are the primary type of natural gas power plants constructed today (SENES for OPA, 2005, p. 24). They are able to capture some of the waste heat created by electricity conversion to create more electricity and can achieve 58% energy efficiency (Gibbons, 2005). Combined-cycle technology can be used for base-load generation and have a higher level of efficiency than single-cycle plants. Consequently, combined-cycle technology is selected to be assessed in this study.

4.2.1.2.2 Wind

The wind turbines evaluated in this study feature the modern horizontal three-blade model, which has become standard for electricity generation in most jurisdictions (Naini et al., 2005). In addition, the turbines are assumed to be part of a wind farm, located on-shore.[59] While utilization of off-shore wind turbines in Ontario may increase at some point in the future, since Ontario currently exhibits a very small base of wind capacity (which is located exclusively on-shore), it is reasonable to assume that wind power developers will maximize the favourable on-shore wind locations first before moving on to the more costlier off-shore variety. This is consistent with the recent request for proposals and planned commitments for wind projects in Ontario, which are all on-shore (Naini et al., 2005).

4.2.1.2.3 Nuclear

In Ontario, the current nuclear fleet is comprised of three main facilities located in Pickering, Clarington and Tiverton, which feature pressurized heavy water Candu technology.[60] Candu reactors utilize natural uranium (0.7%U_{235}) and so-called heavy water (deuterium oxide) as the coolant and moderator. Since natural uranium is used, enrichment is not required and spent fuel is not required to undergo a reprocessing step that is common in other nuclear fuel cycle technologies.

Candu technology was, and continues to be, developed by the Canadian crown corporation Atomic Energy of Canada Limited (AECL) since its inception in 1952. The Candu 6 reactor is the most current model to be installed in Ontario and abroad. Recently, however, AECL developed the Advanced Candu Reactor (ACR), although it currently

[59] According to Retscreen (2006) private costs associated with turbines in a wind farm are lower than if turbines are evaluated on a single, stand-alone basis.
[60] Candu stands for Canadian Deuterium Uranium.

has not been installed anywhere in the world.[61] In the event that new nuclear reactors are built in Ontario, it is unclear at this time as to which AECL technology would be used, or whether Canadian technology would even be used at all.[62]

While it remains a possibility that the Candu 6 technology may not be utilized in a new reactor in Ontario, this study operates under the assumption that Candu 6 will be chosen for several reasons. First, adopting a non-AECL design involves a great deal of technological and regulatory uncertainty involving different components, training for engineers, security issues and licensing and compliance costs. Second, the Ministry of Energy has indicated that its preference is towards Canadian technology (MOE, 2006a). Third, assuming that AECL technology is used, the ACR model does not have any commercial performance to base an evaluation on, which would make the Candu 6 model a 'safer bet' for resource planners.

Since some existing reactors in the nuclear fleet are eligible to be refurbished over the planning horizon and the private costs associated with refurbishment are different than newly built nuclear generation, these alternatives will be evaluated separately (OPA, 2005). The number of nuclear generating units that are available to be refurbished is discussed in section 4.2.4.1.

4.2.1.3 Grid connection and generating unit location

Another criterion for selecting the generation alternatives to evaluate is that they should be integrated with the electricity transmission and distribution grid.[63] This condition is necessary to adequately compare cost figures across generation alternatives. For instance, comparing the cost of grid-tied nuclear power to the cost of a rooftop wind turbine in a

[61] The ACR-700 uses slightly enriched uranium (1.5-2.1%), heavy water as the moderator, light water as the coolant, and according to AECL is expected to be more efficient and cost roughly 15% less than Candu 6 reactors (Naini et al., 2005).

[62] The government may also select from a number of other foreign vendors including American, Korean, British or French nuclear technology organizations.

[63] This should not be taken as an indication that off-grid generation is less valuable than grid-connected supply. In fact, there are numerous benefits of decentralized distributed generation, such as the ability to reduce or delay investment and maintenance in the grid and in centralized supply alternatives; load shifting capability; greater flexibility and system efficiency (US EPA, 2003b).

remote location is unfair due to the scales involved: a centralized nuclear facility requires transmission and distribution infrastructure that serves hundreds of thousands of people, whereas a remote off-grid wind turbine may only serve one business or household and does not utilize the transmission and distribution grid. This study is carried out under the assumption that the capacity expansion alternatives being investigated are grid-tied, regardless of whether they are also capable of distributed generation and this criterion is satisfied by natural gas, wind and nuclear. It is acknowledged that the physical location of a generating unit may have an impact on the marginal costs of bringing the generating unit online. However, a comprehensive evaluation of the transmission costs of each generation alternative is not within the scope of this study.[64]

4.2.2 Step 2: Evaluate private costs of electricity generation alternatives via LUEC analysis

A LUEC analysis is employed to measure the private costs of each electricity generation alternative by determining the electricity cost per kWh that sets the net present value (NPV) of the annual cash flows equal to zero. As noted in Chapter Three, the literature contains conflicting private cost factors and planning assumptions for each generation alternative, so selecting the most appropriate marginal capital costs, fuel costs and operations and maintenance costs for each generation alternative in the Ontario capacity planning context is not straightforward.[65] Moreover, planning assumptions are also

[64] It is assumed that the physical locations of additional generating capacity will be strategically located, such that reliability is maintained at the lowest social cost. Implicit in this assumption is that regional electricity supply requirements are met, replacements for the generation capacity that are taken out of service are done in a coordinated fashion to ensure reliability of supply, integration with the transmission and distribution grid is accomplished in a cost-effective manner, any necessary enhancements to the grid are executed on schedule and all regulatory processes are followed. Although it is acknowledged that there may be unique complexities associated with situating each of the generating units, such constraints appear to be most significant for natural gas generating units (which require expanded gas infrastructure) and wind turbines (which need to be located where wind is strongest, but within close proximity to the grid). These constraints are accounted for in the assessment of private costs. However, external costs associated with transmission are not evaluated in this assessment. Such external effects include visual amenity loss, impact on birds, land use, noise and potential for accident (EC, 2005). Although potentially non-negligible, such costs are assumed to be of a similar magnitude for each generation alternative under study. Therefore it is acknowledged that a limitation of the results may exist depending on whether siting constraints for each generation alternative cause transmission costs to be non-negligible.

[65] In addition to generating unit capital costs, O&M costs and fuel costs, a few other private costs are included for particular generation alternatives, where applicable. For example, infrastructure upgrade costs are included for natural gas, transmission and distribution integration and balancing costs are included for

critical to the calculation of levelized unit electricity costs (Thomas, 2005). The following planning assumptions are required to determine the LUEC results: generating unit capacity, generating unit operating lifetime, average capacity factor and where applicable, heat rate. The first two planning parameters are self-explanatory. The first is expressed in megawatts (MW) per unit and the second in years per unit. The average capacity factor, which is the proportion of electricity that a generating unit produces relative to the amount of electricity that it could produce if it was operating at full capacity, is expressed as a percentage (Ayres et al., 2004). The heat rate, which is a measure of electric efficiency of a generating unit utilizing fossil fuel for electricity production, expresses how much fuel is required per unit of electricity produced in terms of Mcf/kWh.

A consistent methodology is applied to derive private cost estimates for each generation alternative. For all relevant private cost and planning assumption estimates in the literature, the mean will be incorporated for each particular input. Cost figures from academic journals and reports produced by industry, government and non-governmental organizations are utilized.[66] However, the secondary data are restricted to those sources that provide context specific data for the Ontario electricity capacity expansion scenario, so that the marginal costs are most accurate (e.g. costs associated with pressurized water nuclear reactors will not be included since they may be different from the cost of Candu nuclear reactors considered in this assessment. Furthermore, the cost of Candu reactors abroad may be different than that of reactors in Ontario, so only the Ontario figures would be utilized). This approach is consistent with that used in Moore and Guindon (1997, p. 2), which asserts that "[t]he most meaningful comparison is one in which specific plant types meeting the requirements of a country or region are costed in that particular country or region on a common basis".

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wind and waste management and decommissioning costs are included for nuclear generation alternatives. It is noted that such fuel source-specific costs are not included for every generation alternative since they are either non-applicable or negligible relative to other private costs.

[66] Studies often provide a low, central and high estimate. In this situation, the central estimate will be utilized. In addition, if only a low and high are available, the mid-point will be calculated and incorporated into this assessment.

The LUEC analysis is carried out using 2006 as the base year, even though the selection of generation alternatives to fill the forecasted supply gap in 2025 is what is ultimately being assessed. Thus, this study effectively evaluates current generation alternatives to fill a supply gap in 2025. Towards this end, the cost data and planning assumptions that are used reflect current knowledge and the analysis is performed as if construction to build the generating units starts at the beginning of 2006. Although generation capacity that is added to meet the supply gap in 2025 is likely to include an evaluation of the private costs of generation alternatives at a future point in time, the approach undertaken here is assumed to be reasonable. It is noted that although costs will undoubtedly change between now and 2025, a prediction of future cost levels is not within the scope of this analysis.[67] Rather, an evaluation of the generation alternatives as they are today is of central concern and the capacity planning scenario considered here simply helps to put the assessment into context.[68]

General LUEC analysis parameters

Discount rate:

Since it is necessary to evaluate revenues and costs over the lifetime of each generating unit on a common basis, cash flows generated by each alternative in future time periods are adjusted to their present values, a process termed discounting. For example, \$952 invested today at 5% interest will be worth \$1,000 one year from today. In other words, the present value (PV) of \$1,000 in this case is \$952.[69] In general, present value is expressed by the following equation:

[67] However, it would be a worthwhile exercise to re-perform this analysis again in the future to see what impact the updated costs and assumptions would have on the results.
[68] In addition, the timing with respect to activating the generating units between 2014, when the initial supply gap is forecasted to occur, and 2025, when the gap of 7,000 MW is expected to exist, may also have significant implications for the cost assessment, but such concerns are also not considered within the scope of this analysis.
[69] Calculation: 1,000/1.05 = 952.

Present Value = cost t years into the future / $(1 + r)^t$,

where r is the discount rate and t is the time in years.

The discount rate can be communicated in nominal terms, but most of the time it is adjusted for inflation, in which case it is known as the real discount rate (Perman et al., 2003).[70] This is accomplished by simply subtracting the inflation rate from the nominal discount rate. Using a real discount rate allows one to avoid forecasting inflation rates. In this assessment, all dollar values are given in real dollar terms (i.e. in terms of the purchasing power of a dollar for the base year 2006).[71]

Discounting is based on two main concepts: the risk-adjusted opportunity cost of capital and time preference. Opportunity cost refers to the return that could be obtained from the next best alternative use of capital with the same level of risk. Therefore, the risk-adjusted opportunity cost of capital is the payment that is required by financiers to invest in a project that exhibits increased risk. In addition, time preference, which is the premium that is required for one to receive money at some point in the future rather than the present, is also of importance. Both of these concepts are inherent in the selection of the discount rate.

The discount rate reflects how much we are willing to give up in consumption in the future in order to receive a dollar's worth of consumption today. In the numerical example given above, a 5% discount rate indicates that one would be willing to give up \$1,000 next year if compensated with \$952 today. In other words, one is indifferent between receiving the \$952 today or \$1,000 in a year's time.

The discount rate that should be used to assess generation alternatives depends on the desired perspective. If we are interested in evaluating a project in terms of what is best for society as a whole, the appropriate discount rate would be different than if we were

[70] Inflation is defined as "a persistent rise over time in the average price of goods and services" (Bank of Canada, 2006).
[71] Hereafter the discount rate refers to the real discount rate, unless otherwise noted.

interested in the perspective of a private firm. For a social, or public, perspective, the discount rate should reflect the rate at which society is willing to tradeoff consumption today with consumption in the future. That rate (the social discount rate) will depend on the return that can be obtained on other alternative investments (the opportunity cost) adjusted for risk. Society will demand a greater return (i.e. a higher discount rate) from a project that is inherently more risky than another project. The social discount rate will also reflect society's concern for future generations. An increase in the discount rate means that we are putting less weight on costs and benefits that occur far into the future. Hence, the choice of a social discount rate implies value judgments about the extent to which we are concerned with future generations. In this assessment, it is assumed that a social discount rate would be used by government agencies to evaluate projects.

The discount rate that would be used by a private, or merchant, firm differs from the social discount rate for several reasons. Most obviously, a merchant firm has less incentive to be concerned with future generations (i.e. to delay their consumption until some point in the future). Furthermore, a merchant firm may require greater compensation for increased risk since a firm is unable to diversify investments as easily as a government could. Consequently, investors in a private firm require a higher rate of return to offset the increased risk that is associated with a merchant project in, for example, the quasi-competitive Ontario electricity market. Therefore, the discount rate from a merchant perspective would be higher than the social discount rate.

The theoretical principles regarding the choice of discount rate are well understood (e.g. EC, 1999a). However, the practical choice of a discount rate is controversial, particularly when it comes to a social discount rate.

In this thesis, the approach of Ayres et al. (2004) is adopted whereby the discount rate is chosen to reflect the cost of financing the project. The social discount rate is assumed to be the cost of a publicly financed project as given by the long-term cost of public debt. A discount rate of 5%, which is the rate used by the Government of Ontario to evaluate long-term projects, is incorporated into this analysis to evaluate generation alternatives from a public perspective (Spiro, 2004 cited in DSS for MOE, 2005). Note that the underlying assumption is that the interest rate charged on long-term debt is the correct rate at which society would be willing to trade off current for future consumption.[72]

The merchant discount rate is taken as the cost of financing a private project based on specific assumptions about the level of debt and equity financing. In this assessment, it is assumed that merchant projects are unlevered (i.e. they are financed with 100% equity and 0% debt). According to Ross et al. (2005, p.212), the "approach of assuming no debt financing is rather standard in the real world." Therefore, the discount rate reflects the cost of equity (and time preference) for each merchant project. The cost of equity that should be included in the analysis is determined in the same fashion as other private cost factors and planning assumptions: an average value is taken from the literature. Hence, the merchant discount rate for each generation alternative evaluated in this assessment is 13%.[73]

In the sensitivity analysis, which is discussed further in section 4.2.5.2, different levels of debt financing are tested to determine the effect thatdebt has on the social cost estimates. When debt and equity are used to finance a merchant project, the discount rate reflects the weighted average cost of capital (WACC)[74], which is calculated as follows:

WACC = (cost of equity x (1 – debt-to-equity ratio)) + (cost of debt x debt-to-equity ratio x (1- tax rate))[75]

[72] In the public perspective, it is assumed that the government is able to diversify risk and is able to underwrite any cost overruns. Regardless of the generation alternative evaluated in the public scenario, the government will be able to meet its debt obligations with a high level of certainty.

[73] This figure is based on the average cost of equity obtained from: Ayres et al., 2004 (12%); Navigant, 2005 (14%); and OPA, 2005 (12%) and is applicable to each generation alternative.

[74] There are two other standard approaches to valuation when debt is used besides the Weighted Average Cost of Capital Method: the Adjusted Present Value method and the Flow to Equity method. All three methods will arrive at the same result (Ross et al., 2005). However, according to Ross et al. (2005, p. 513), "WACC is by far the most widely used method" and therefore will be adopted here.

[75] The discount rate in an all-equity project can still be considered a reflection of the WACC, but since the percentage of equity financing is 100%, only the cost of equity is a determinant of the cost of capital.

When debt and equity financing are used and the discount rate reflects the weighted average cost of capital, interest expenses and the receipt and repayment of the principle of the debt are already accounted for. Therefore, they should not be included in the LUEC analysis as this would result in double counting. Ross et al. (2005, p. 212) note that "[a]ny adjustments [to cash flows] for debt financing are reflected in the discount rate, not the cash flows."

Income tax:

In addition, unlike government, private firms are subject to income taxes, so this expense is included in the LUEC analysis under the merchant perspective as well. The combined federal and provincial tax rate adopted here is 36%, which is consistent with Ontario Power Generation's tax rate (OPG, 2006a). Taxes are calculated on net income after depreciation has been subtracted. Depreciation is calculated on a straight-line basis, which is also in accordance with Ontario Power Generation's method of accounting for depreciation (OPG, 2006a). Annual income tax for each generation alternative is determined by the following equation:

Income tax = (net income before depreciation and tax – depreciation) x 36%

Note that depreciation is only calculated for tax purposes and does not have an actual effect on cash flow. Rather, cash flow is decreased when the actual capital expenditure is incurred. Therefore, annual depreciation must be added back to net income after tax to properly reflect annual cash flow. Townley (1998, p. 147) asserts that "if both the capital cost of a project and corresponding depreciation charges were included in the net present value, the cost of the project would be overstated. That is, inasmuch as the sum of depreciation allowances reflects the initial capital cost, this cost would be double-counted. Therefore, analysts should include only capital costs and ignore depreciation [for cash flow purposes]."

Since interest payments are already accounted for by adjusting the discount rate when debt financing is utilized, the tax benefit (i.e. the amount of tax that is reduced as a result of utilizing debt) is already accounted for and any further adjustments would be double counting. This is because debt costs are determined after tax in the WACC calculation.

LUEC results are presented under both public and merchant perspectives, which demonstrate the impact that financing and taxation have on the evaluation of the generation alternatives.

Other general LUEC analysis parameters used to derive private costs include:

- Revenue: Annual revenue is generated by the sale of electricity. For the purpose of the LUEC analysis, the annual revenue per kWh for each generation alternative is determined by the following equation:

generating unit capacity (MW) x average capacity factor (%) x 24 x 365 x 1,000 x price of electricity per kWh that sets the sum of the annual discounted cash flows over the lifetime of the generation alternative equal to zero[76]

- Construction period: The construction period and corresponding construction costs for each generation alternative are based on the assumptions used in Ayres et al. (2004). The years in the construction period which occurs before the generating unit comes online are designated in negative numbers. For example, if construction is expected to take two years to complete, the first year of construction is denoted Year -2, the following year is shown as Year -1 and the first year of operation is Year 1. The cost associated with each construction year is expressed as a percentage of overnight capital costs.

[76] For the LUEC analysis, annual revenue is expected to be constant every year that the generating unit is in operation. Of course, in reality the supply from a generating unit and thus the revenue it generates is likely to fluctuate due to short-term factors such as the time of day and season and long-term factors such as modifications to the supply mix like eventual coal plant shut downs (Navigant, 2005). However, this assessment is based on average capacity factors which produce average costs over the operating lifetime of a generating unit. Thus, marginal costs are estimated by assuming that the average capacity factor is “locked in” over the operating lifetime of the generating unit.

- Base year: Unless otherwise noted, all cost figures are expressed in real Canadian dollars with 2006 as the base year. Cost data utilized from prior years are inflated to 2006 dollars at the historical inflation rate utilizing the Bank of Canada inflation calculator to account for the effect of inflation on purchasing power. This tool, found on the Bank of Canada website, uses consumer price index (CPI) data, which measures the cost changes in a "fixed basket of consumer purchases", to inflate dollars from one year to another (Bank of Canada, 2006).[77]

- Exchange rates: A United States-Canadian exchange rate of US$1 = CDN$1.10 and an European Union-Canadian exchange rate of €1 = CDN$1.40 are used (Bank of Canada, 2006).[78]

- Solver tool: The LUEC is determined by using the Solver function in Microsoft Excel. Based on the private cost factors, planning assumptions and general parameters incorporated into the analysis, this tool is able to calculate the price per kilowatt-hour that sets the NPV of the annual cash flows over the lifetime of the generating unit equal to zero based on a given discount rate.[79]

4.2.3 Step 3: Evaluate computable external costs associated with each generation alternative

As is the case with private costs, secondary data in the literature are relied upon for external cost estimates. Electricity externality studies are used to estimate the computable external burdens for each generation alternative. Figure 4-2 depicts the process and

[77] The Consumer Price Index (CPI) is "The most widely used measure of inflation...It reflects changes in the price of a representative 'basket' of goods and services sold in Canada: food, housing, transportation, furniture, clothing, recreation, and other items that Canadians buy" (Bank of Canada, 2006).
[78] Exchange rates reflect the prevailing rates as of June, 2006.
[79] This is accomplished by setting the NPV as the target cell equal to zero, and by making the changing cell the cell that holds the price per kWh. This problem is a circular reference since the price per kilowatt-hour is tied to the revenue generated per year (revenue equals number of kWh generated per year x unit price per kWh). Refer to Appendix C (i) for a further description of LUEC calculations, in which the calculations for wind generation in the merchant perspective are explained in greater detail.

criteria used to filter the external cost estimates that are incorporated into this evaluation. Each phase is further explained below.

Figure 4-2: Computable external burden assessment filter process and criteria

Filter Phase	Filter Criteria
Filter phase 1: Analyze previous studies that employ the bottom-up damage cost method to determine computable external burdens	Identify the computable external burdens for each electricity generation alternative
Filter phase 2: Estimate computable external burdens for each generation alternative under study	Use benefit transfer to obtain monetized external costs for computable external burdens
Filter phase 3: Comply with assessment parameters	Temporal and geographical constraints, avoid double counting
Computable external costs	

4.2.3.1 Filter phase 1: Analyze previous studies that employ the bottom-up damage cost method to determine computable external burdens

Each electricity generation alternative produces a number of external burdens. These can be classified into four broad categories: environmental and human health burdens; climate change burdens; risk of accidents; and energy security risk (EC, 2005).

Environmental and human health impacts are caused by emissions of noise, radiation, heat and pollutants released into the atmosphere, land or water. Such emissions either increase risk or cause damage to receptors such as ecosystems, the built environment or human health (EC, 2005). Climate change impacts are a subset of this category, but since the uncertainty associated with such impacts is significantly higher than other impacts, they are evaluated independently.

Accidents are events that are not expected to occur during routine operation that may have an impact on the general public. Furthermore, risk aversion to catastrophic impacts with a low probability of occurring is an additional kind of accident-related cost (EC, 2005).

The risks associated with energy security failures are another set of external impacts. Such burdens refer to costs associated with obstacles that may prevent the use of resources for electricity generation, such as restrictions on resource accessibility and the threat (based on past experience) that generating units will endure “unscheduled”, out-of-service periods. In addition, the risks associated with nuclear proliferation, which is unique among all burdens, falls under this category.

So that external effects can be monetized, it is first necessary to identify the subset of computable external burdens from the larger pool of external effects associated with each generation alternative under study. Once identified, such burdens will be quantified and monetized and these values will be added to the private levelized unit electricity costs to arrive at a total social cost for each alternative.

Computability

Ideally, it would be possible to identify, quantify and monetize each and every external burden for each generation alternative. However, only a subset of these impacts is computable. Whether or not a particular external burden is computable and thus should be quantitatively assessed depends on three factors: data availability, monetization ability and relative magnitude (adapted from Altnatheer, 2006). An external burden is monetized if sufficient data are available, the impact has the ability to be monetized and the value of the monetized burden is non-negligible compared to the other external costs for each generation alternative under study. All other external burdens are not monetized within the scope of this assessment, although some potentially significant incomputable burdens, as identified in the literature, are discussed in qualitative terms.

Data availability:

Obviously, data for a particular external burden must be available in order for it to be quantified. A burden may be known to exist, but may be too poorly understood to be properly documented in the literature. Consequently, some dose-response functions are not developed because the precise attribution of external effects originating from a particular source can be a challenge or because the costs of developing a defensible dose-response function are too high. Quantifying external burdens can be complex, involving multiple factors and scientific uncertainties. The interaction between pollutants and the potential for cumulative effects may preclude reliable models for some impacts (Sundqvist, 2002). For example, determining the precise impacts associated with an accident in the waste management stage of the nuclear fuel cycle is extremely difficult. Moreover, it is reasonable to conclude, given the limited understanding of ecological processes, that some burdens have yet to be discovered. For instance, the hole in the ozone layer caused by the release of CFCs in the atmosphere was not discovered until years after CFCs had been originally developed and several years after their impact was hypothesized (Benedick, 1998). Hence, it is possible that various ecological processes or impacts may remain unknowable in the future.

Monetization ability:

Some burdens lack monetization ability since individuals' willingness to pay for certain impacts may be unobtainable. This may occur if individuals' familiarity or understanding of complex burdens is insufficient to allow them to develop a preference towards (and thus, willingness to pay for) a particular burden under investigation (Sundqvist, 2002). For instance, although monetization techniques are used to value damages to household materials from air pollution, valuing the damages to the building materials of structures that have cultural value has not been carried out to date but may be of significance

(Dones et al., 2005). However, as noted in section 3.3.2.3, researchers may look to experts or politicians as a second-best option for the impacts that are, as yet unobtainable. However, these are only "appropriate to the extent that the choices of policy makers correctly reflect the underlying values of the population" (EC, 2005, p.22).

Relative magnitude:

In addition, external burdens are computable if they are non-negligible relative to the other the external burdens associated with each respective generation alternative.[80] Most electricity externality studies (e.g. ORNL & RfF, 1998) utilize a pre-screening assessment whereby experts determine various impacts that are expected to be orders of magnitude smaller than larger impacts, which are then omitted from the analysis (Sundqvist, 2002). While not accounting for negligible burdens understates the results of some generation alternatives to some extent, such burdens are believed to be small enough to be considered inconsequential in relation to other external effects (i.e. the burdens are technically computable even if they are small, but are simply not worth estimating since they would not appreciably increase the external cost estimates). According to Venema and Barg (2003, p. 19), efforts to quantify such impacts "will have negligible effect on the accuracy of the total damage estimation". For instance, damages to household materials from air pollution associated with coal-fired plants are so small compared to the potential impacts of, say, climate change that quantifying and monetizing them would be irrelevant (DSS for MOE, 2005).

4.2.3.2 Filter phase 1 criteria: Analyze previous electricity externality studies that employ the bottom-up damage cost method to determine computable burdens

Relevant electricity externality studies from the literature are evaluated to determine which external burdens are computable. Only studies that utilize a primarily bottom-up

[80] The fact that an external burden is negligible relative to total external costs may not necessarily imply that it is unimportant or negligible in absolute terms. In fact, it may have a considerable effect on various segments of the population. ExternE (EC, 1999b, p. 20) states that "It will not inevitably follow that action to reduce the [negligible] burden is unnecessary, as the impacts associated with it may have a serious effect on a small number of people".

damage cost method with supplemental valuation techniques for some impacts are considered. As discussed in Chapter Three, such an estimation framework is preferable due to its ability to reflect site and receptor specificity and to account for some otherwise incomputable impacts.[81] External cost estimates found in the literature reflect the external burdens for which there are sufficient data and monetization ability to allow for monetary cost estimation.[82] The purpose, then, of analyzing the results of these studies is to identify the external burdens that are relatively non-negligible.

To carry out this assessment for each generation alternative, external burdens are expressed as a percentage of the total external costs for each particular electricity externality study that is evaluated.[83] Once the percentages have been calculated, a mean value for each external burden is taken across the studies to determine the proportion that each contributes to the total external cost estimates, on average. The largest individual burdens whose sum represents 80% or more of the total external costs, on average, of each generation alternative are considered to be non-negligible. Hence, it is notable that the same kind of external burden may be considered negligible for one generation alternative and non-negligible for another (e.g. the impact of emissions associated with the construction of a generating unit is considered to be computable for wind but not for natural gas and nuclear).

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[81] Although the estimation framework utilized in the studies evaluated here is generally consistent, their results are a function of site and receptor characteristics and various key underlying assumptions. For example, the discount rate used to estimate external cost figures for long-term health impacts associated with the nuclear fuel cycle can have a significant impact on the overall external cost results for this generation alternative. Consequently, this will influence the relative magnitude of each particular external burden. This effect is magnified since the sample size of relevant electricity externality studies using a bottom-up damage cost methodology is rather small. Therefore, it must be acknowledged that if the data in the literature is based on flawed assumptions, this will be reflected in the results obtained here. In particular, the findings of the ExternE projects will have a significant weighting on the results of this study, since the majority of the studies used to derive the results of this analysis are part of the ExternE research projects. On the one hand, this is not ideal since one set of assumptions are relied upon disproportionately. However, on the other hand, this is not necessarily unfavourable since ExternE is considered to be the foremost authority in electricity externality research.

[82] It is noted that the strength of the approach used here rests with the quality of the electricity externality studies included in the literature. Therefore, it is acknowledged that if the literature fails to account for some otherwise computable external burdens, the results of this study will reflect this omission, which is considered to be a limitation of this approach.

[83] Base-case figures from the individual studies are used. If a base case is not identified and low, central and high estimates are presented, the central estimates are used. When a reference-case scenario is not identified and there is a lower and upper estimate the midpoint is used.

External burdens considered to be non-negligible are then quantified and monetized for the Ontario capacity planning context. In addition, several incomputable burdens identified in the literature are also discussed in qualitative terms, albeit with a greater emphasis on the particular incomputable external effects that exhibit poor data availability and/or monetization ability but which are thought to be potentially non-negligible.

4.2.3.3 Filter phase 2: Estimate computable burdens for each generation alternative under study

The next step, once computable burdens have been identified, is to quantify and monetize the marginal external costs of such burdens for Ontario electricity generation alternatives. The most relevant secondary data from previous electricity externality studies are employed to carry out this step in an approach that is known as benefits transfer.[84] The monetized external cost figures are added to private levelized unit electricity costs to arrive at total social costs for each generation alternative.

4.2.3.4 Filter phase 2 criteria: Use benefit transfer to obtain monetized external costs for computable external burdens

The benefit transfer approach does not require an original external cost valuation to be performed. Rather, the findings of previous studies may be used to represent individuals' preferences towards external burdens for the context that is under consideration (Sundqvist, 2002). Results from past studies may be utilized directly or they may be adapted to reflect site and receptor specificity, as required. Rosenberger and Loomis (2001 cited in EC, 2005, p. 23) define benefit transfer as "the adaptation and use of existing economic information derived for specific sites under certain resource and policy conditions to new contexts or sites with similar resources and conditions".

[84] Also referred to in the literature as value transfer (Navrud, 2004).

Although it is recognized as a legitimate approach for use in external cost valuation studies, it must be used with caution since not all data are appropriate for transfer (EC, 2005). At times, the information being transferred may have to be adapted (e.g. scaled up or down) to properly account for local site and receptor specific characteristics. If more than one study is relevant, then average values may be transferred (EC, 2005). According to ExternE (EC, 1999, p. 43), "[t]he difficult issue is to know when a damage estimate is transferable and what modifications, if any, need to be made before it can be used in its new context".

Benefit transfer is not a replacement for original research. It is useful to researchers in the sense that it minimizes redundancy, not because it is necessarily more precise (Garner, 2002). ExternE (EC, 1999a, p. 28) notes that although benefit transfer may not be ideal, it "is to be preferred to ignoring particular types of impact altogether – neither option is free from uncertainty". For example, a primary questionnaire asking respondents about their willingness to pay to avoid premature mortality is better than using a similar study obtained in another region. However, using existing data and adapting it to another context can still provide a sufficient level of accuracy since data obtained from the original study site is, for all intents and purposes, assumed to be comparable to what would be obtained if an original study was undertaken at the policy site (i.e. Ontario), as long as the contexts in both cases are reasonably analogous.

The key point for benefit transfer is that researchers cannot just transfer anything they want: the data should be relevant to the nature of what is required. According to Navrud (2004), benefit transfer between regions with many different socioeconomic characteristics (which have an impact on determining preferences) should not be used (EC, 2005). Towards this end, ORNL & RfF (1992, p. 5-26) states that:

> The care and effort used in conducting a benefit transfer, and indeed whether one should attempt it at all, depend on the commodity being valued, differences in regional, site and personal characteristics, and the nature of the original literature being relied upon for the benefit transfer…indeed, without careful reporting of results in the original study, this approach may be impossible.

Thus, it is important for researchers to be transparent with respect to what is being transferred and whether any modifications are made to the original data.

It is noted that for the purpose of this evaluation, however, that no new modelling, impact analysis or valuation estimates are undertaken. Rather, the cost estimates that are transferred from other studies will only be adjusted to account for exchange rates and inflation. Therefore, the use of secondary data may cause some inconsistency in the presentation of the results. For example, a particular capacity factor or discount rate used to derive the results of premature mortality associated with natural gas-fired electricity generation may be different than the capacity factor or discount rate used to derive private costs in the LUEC analysis undertaken here. If the external costs estimates derived by secondary sources use different planning assumptions than those incorporated into this study's private cost LUEC analysis, this inconsistency is documented in a transparent fashion and is acknowledged as a limitation.

<u>Determining appropriate benefit transfer data</u>

The following guidelines are used to govern the selection of external cost data for this assessment:

- External cost data for generation alternatives is confined to electricity externality studies that employ a predominantly bottom-up damage cost approach to quantify external burdens and other appropriate context-specific valuation tools for particular burdens, as warranted
- Preference is given to studies that exhibit the greatest degree of similarity with the Ontario capacity expansion alternatives in terms of site and receptor characteristics
- Preference is given to more recent studies if more than one study has been conducted by the same researchers
- Preference is given to studies that provide a transparent explanation of methodology and assumptions used to estimate external costs

The potential for researcher bias to skew the way benefit transfer data are applied must be acknowledged. There exists the possibility that the values and preferences of the author may become embedded in the benefit transfer process (either deliberately or unintentionally) since the objectives and values of the author may influence their decisions (Kammen and Pacca, 2004). According to US EPA (2003b, p. 6):

> Valuation of non-market costs and benefits is necessarily more subjective, and different individuals and groups disagree about monetary values. Thus, transparency in data sources and sensitivity analyses or methods that acknowledge the range of possible values are especially important in analytic efforts seeking to incorporate externalities.

Consequently, principles of transparency, consistency and comprehensiveness, which are practiced by the ExternE project are employed here by rigorously documenting the methods and assumptions used to derive external cost estimates (EC, 2005). However, this concern can only be partially mitigated since the selection and adaptation of the secondary data remains at the discretion of the author.

4.2.3.5 Filter phase 3: Comply with assessment parameters

The computable external cost figures applied to the generation alternatives under evaluation are subject to temporal and geographical boundaries. In addition, double counting of some external effects must also be avoided. Complying with these parameters improves the accuracy of external cost estimates.

4.2.3.6 Filter phase 3 criteria: Comply with temporal and geographical constraints and avoid double counting

Temporal boundary:

External impacts should be accounted for even if the impacts are incurred after the generating unit has been retired. Most of the computable external burdens evaluated are expected to be incurred by receptors during the operating lifetime of each generating unit.

However, some burdens have the potential to affect receptors after the generating unit has been shut down, in some cases well into the future (e.g. climate change impacts and nuclear waste management). Evaluating long-term impacts is more complicated since the means to adapt and mitigate the impacts and the preferences of future generations are uncertain. Wherever possible, the assessment of long-term effects will aim to reflect the complete package of impacts that are estimated to accrue over time.

Geographical boundary:

All the external burdens caused by electricity generation in Ontario should be included in the evaluation of external costs, even if the actual impacts are incurred by receptors in neighbouring jurisdictions. This may occur as a result of upstream or downstream processes that are carried out outside of Ontario to facilitate electricity generation inside the province. For instance, if the uranium that is used for nuclear power generation in Ontario and mined in Saskatchewan imposes an external burden on the general public in Saskatchewan, this cost should be included in this assessment because it is incurred for the purpose of generating electricity in Ontario. Similarly, pollution released in Ontario that crosses into other electricity jurisdictions, should also be accounted for. For example, climate change impacts resulting from the emission of GHGs are expected to have a global reach.

The opposite holds true for external burdens that affect receptors in Ontario yet originate elsewhere and such burdens are omitted from this study. For instance, the long range transport of emissions from various sources in the United States is thought to play a significant role in contributing to ambient air pollution concentrations in Ontario (Yap et al., 2005). Impacts resulting from these emissions would not be included in the external cost estimates of electricity generation alternatives in the province.

Double counting:

Due to the nature of the estimation of external costs, it is important to ensure that double counting is avoided so that cost estimates are not overstated. A distinction is made between two different kinds of double counting errors: counting the avoided costs of one generating alternative as the benefits of another and errors associated with counting external costs that have already been internalized.

If the costs of using a particular generation alternative are equivalent to the benefits of using another they should not be counted twice in the analysis. In such a situation, only the costs should be counted. For example, nuclear and wind are associated with producing less GHG emissions than natural gas-fired electricity. Rather than assigning these generation alternatives a benefit (via a deduction to their respective external cost estimates), the costs associated with GHG emissions are charged to natural gas-fired generation.[85] In this case, if nuclear and wind had received a cost deduction, natural gas would have been penalized twice: once for incurring the cost itself and a second time when the external cost estimates for nuclear and wind are reduced by the same amount. In this situation the costs and benefits can be considered "two sides of the same coin" and should not be counted twice.

Another possibility for double counting arises when previously external costs become internalized. When this occurs, only the uninternalized costs should be counted. For example, decommissioning and waste management costs are expected to be non-negligible for the nuclear generation alternatives. However, nuclear operators in Ontario are required to make annual payments to a fund that will be used to pay for these expenses when they are incurred in the future. Therefore, to the extent that the amount that is allocated to the fund is able to cover future costs, these costs would be internalized and should be counted as private costs. In this case, if the decommissioning and waste management are also counted as external costs, then double counting is occurring.

[85] Indeed nuclear and wind powered generation, which also produce a small amount of GHG emissions in various upstream processes, would also be charged with climate change costs, but to a far lesser extent than natural gas.

In addition, it is argued that health damages incurred in the process of working (i.e. occupational health burdens), are already internalized since workers are assumed to be well informed and aware of the risks that their job entails and that their compensation is reflected commensurately. According to Maddison (1999), worker-related accidents are already internalized so including them in an assessment of resource planning options results in double counting. Consequently, where such burdens have been included in the external cost estimates in the literature, they have been omitted for the purpose of the computable burden assessment (i.e. they are subtracted from the external cost figure before the assessment is carried out). However, it is acknowledged that if workers do not have a full understanding of the risks of their job, or if the labour market limits changing jobs without difficulty, this may not be accurate, which would be a limitation of this analysis.[86]

4.2.4 Step 4: Aggregate private and external costs for each generation alternative and apply social cost results to Ontario capacity planning context

Social costs are then calculated by aggregating the private costs and external costs associated with each generation alternative. Once social cost estimates have been derived, they are used to determine the capacity expansion scenario that meets 2025 demand requirements at the least cost to society. Based on currently installed capacity and already planned generation commitments expected to be available in 2025 and the implementation of conservation and demand-side management initiatives proposed by the government, a supply gap of 7,000 MW is forecast. The criterion used here to fill this gap is simply to select the generation alternative(s) that has the lowest social costs subject to any capacity expansion constraints.

[86] Although there is a lack of conclusive evidence, ExternE (EC, 2005) assumes that 80% of occupational health burdens are internalized. However, it notes that this figure was selected based on speculation and may be unreliable due to the lack of available data. It also notes that the percentage may in fact be as high as 100% in OECD countries, which is the assumption adopted here.

4.2.4.1 Technical capacity expansion constraints

Technical capacity expansion constraints refer to the maximum level that each generation alternative can be allocated to fill the estimated supply gap in 2025, where applicable. In terms of meeting the forecasted supply gap, neither natural gas-fired generation nor new nuclear generation are associated with any technical capacity expansion constraints. However, while no technical capacity constraints are present for these generation alternatives, it is widely accepted that a diverse supply mix can improve system reliability and mitigate unintended consequences that affect particular generation alternatives within the supply mix to some extent.[87]

The nuclear refurbishment scenario, which involves the rebuilding of the reactor core, is constrained by how many existing nuclear reactors in the fleet are available to be refurbished. Ontario currently has 20 nuclear reactor units, of which 18 are deemed fit for use.[88] Two units at Pickering A were refurbished and returned to service in 2003 and 2005, bringing the total number of active units in Ontario to 16 at the time of writing. Barring a delay, two out-of-service units at Bruce Nuclear Station that have been contracted to be refurbished are expected to come online in 2009. Two more units at Bruce A are also contracted to be taken out of service to undergo renovations by 2010 and 2011 as well (Bruce Power, 2006a). Thus, the four reactors at Pickering A and the four reactors at Bruce A are considered to be ineligible for refurbishment. In contrast, the four reactors at Pickering B, the four reactors at Darlington and the four reactors at Bruce B are scheduled to go offline in a gradual process over the next two decades and these

[87] It is technically possible for these generation alternatives, which are assumed to be providing base-load capacity, to generate 100% of the total supply mix. However, OPA (2005) indicates that it would be efficient for 63% of total electricity generating capacity in Ontario to be counted on to provide base-load generation. In 2025, this base-load target is expected to be 18,900 MW. Given that approximately 9,000 MW of the currently installed or already planned capacity is forecast to be available in 2025 can be used for base-load generation, roughly 9,900 MW of additional base-load capacity could be added before the 63% target is surpassed (OPA, 2005). It is noted that while it would be possible to utilize base-load generation sources beyond this amount, it becomes costlier to do so since the generating units are rendered idle for some length of time. Consequently, since the 9,900 MW of base-load capacity is larger than the actual capacity expansion proposed (7,000 MW), there is no capacity constraint associated with nuclear or natural gas generation options. Thus, it is assumed that even if natural gas or new nuclear is used to completely fill the complete supply gap, the total supply mix in 2025 is considered to be sufficiently diversified such that reliability in the system is maintained.

[88] Pickering A units 2 and 3 will not be returned to service due to the prohibitively uneconomic cost of doing so (OPG, 2006a).

reactors are considered to be eligible for refurbishment during this period.[89] Consequently, it is assumed that 12 reactor units have the potential to be refurbished. However, for the purpose of this evaluation, only six "blocks" of reactor units are considered to be available for refurbishment.[90] Refurbished reactor units are assumed to have an average generating capacity of 752 MW.[91] Therefore, the nuclear refurbishment scenario exhibits a technical capacity constraint of 4,512 MW.

Technical constraints are also associated with wind-powered electricity generation due to its intermittent nature. Belanger and Gagnon (2002, p. 1279) note that "[e]ven on a site with a high wind power potential, the wind blows and stops frequently on a short time basis and could be totally absent when most needed". However, some intermittency can be mitigated by spreading turbines out geographically and by backing them up with another generation source although the larger the amount of wind capacity that is added to the system, the more backup generation is needed to meet peak demand and the greater the cost becomes (Belanger and Gagnon, 2002; Owen, 2004b).[92] Moreover, reliability may be compromised at a certain threshold depending on the electricity system (NEB, 2006).

Consequently, various jurisdictions have implemented a ceiling for integrating wind capacity into their supply mix to ensure that reliability in the system is maintained.[93]

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[89] For a timetable of when Ontario nuclear are scheduled to go offline, refer to OPA supply mix advice report, 2005, section 1-2, p. 17. Actual out-of-service dates may not correspond with this schedule. It is also noted that new developments may preclude any of the 12 eligible units from being refurbished.

[90] This is because the operating lifetimes of nuclear refurbishment projects are approximately half of that associated with the other generation alternatives under evaluation. To maintain consistency in the LUEC analysis, refurbishments are required to be assembled in "blocks" of two so that their operating lifetimes are effectively doubled. Therefore, instead of 12 reactors available for refurbishment, there are six.

[91] This average encompasses the four units at Pickering B (516 MW each), four units at Darlington (881 MW each) and four units at Bruce B (769 MW each).

[92] Various generation sources such as hydro or natural gas may be utilized as backup to improve supply stability, albeit at an increased cost.

[93] The maximum allowable proportion of wind to total generation capacity varies depending on the jurisdiction but appears to be in the 10-20% range. Retscreen (2006) notes that the percentage may be as high as 25%. NEB (2006, p. 15) states that "The amount of wind power an electric power system can absorb depends on its configuration. Based on technical studies and experience in Europe and in the U.S., a predominantly thermal system is expected to be able to function normally with up to 10 percent of its installed generating capacity being wind turbines, whereas a mainly hydro-based system could support up to 20 percent more wind power". It also notes that "The Danish grid can integrate a high proportion of wind

Towards this end, OPA (2005) specifies that wind capacity should not exceed 15% of total installed capacity, which is assumed to be a reasonable constraint for the purpose of this assessment. Therefore, based on the projected levels of demand and supply in 2025 and the already planned wind installments, the technical maximum amount of additional wind capacity that may be added to the Ontario supply mix by 2025 is 3,100 MW.[94]

4.2.5 Step 5: Recognize uncertainty in the base case results and employ a sensitivity analysis to mitigate uncertainty

Since there are conflicting values in the literature for private and external cost estimates associated with electricity generation alternatives, any values included in the analysis will contain some uncertainty. There are various limitations inherent in the methodology and the assumptions used to estimate both private and external costs. For instance, marginal fuel costs over the operating lifetime of a generating unit are uncertain as are estimating the impacts associated with external burdens such as greenhouse gas emissions or potential accidents. While the range of uncertainty for cost estimates is unknown, ExternE (EC, 2005) - which some of the external costs that this study are based on - notes that its results are accurate to within 2 to 4 times (+/-) its reference scenario, which could provide some indication of the range of uncertainty of the results derived here. It is noted that although uncertainty with some cost estimates exists, such estimates are superior to having an infinite amount of uncertainty, which would be the case without including them in the analysis (EC, 2005). To increase the validity of the social cost estimates derived here, the implementation of this assessment aims to respect the principles of consistency, transparency and comprehensiveness. To further mitigate some of the uncertainty in the capacity expansion plan derived in the base case, a sensitivity analysis is employed.

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power (about 20 percent of supply) because it benefits from good interconnections with neighbouring countries (i.e. Sweden, Norway and Germany) that can provide backup power" (NEB, 2006, p. 14).

[94] Calculation: Approximately 30,000 MW of forecasted supply capacity required in 2025 (net of CDM) x 0.15 = 4,500 MW – 1,400 MW of procurements already in place = 3,100 MW.

4.2.5.1 Consistency, transparency and comprehensiveness

The nature of this kind of assessment does not allow for definitive criteria to be used to assess the accuracy of the social cost estimates. While the calculations and their application to the forecasted supply gap can be scrutinized to ensure that analytical rigour has been applied, the appropriateness of the underlying input data are less objective. Consequently, the standards of consistency, transparency and comprehensiveness are employed to increase the credibility of the estimates. For private costs, this is manifested by taking the average of the private cost factors and planning assumptions obtained in the literature. For external costs, a consistent computable external burden assessment is used first to identify the computable external burdens for each generation alternative and then to acquire the most appropriate secondary data in the literature using the benefit transfer method. It is important to be consistent and comprehensive in order to minimize the possibility of "cherry picking" diverse trade-offs associated with the generation alternatives. In addition, presenting the results in a transparent fashion, so that the findings may be evaluated in a meaningful way, is also necessary.

4.2.5.2 Sensitivity analysis

The sensitivity analysis evaluates the impact of changes to several key variablesrelative to the base case (i.e. by altering one variable at a time while holding all others constant).[95] This can show how sensitive the results of the analysis are to changes in key variables, identify which variables have the most significant influence on the results and determine whether the ranking of generating alternatives would be affected by such changes. The variables tested in the sensitivity analysis are discussed in Chapter Five.

[95] It is acknowledged that this does not allow for testing of correlation between variables (Ayres et al, 2004).

4.3 Chapter summary

This chapter provided a methodological framework to assess the private and external costs of electricity generated by natural gas, wind, nuclear refurbishment and new nuclear generation. In the following chapter, the social cost assessment is implemented by following this framework.

Chapter 5 Social cost assessment and data analysis

5.1 Introduction

Step 1 of methodological framework outlined in Figure 4.1 was carried out in Chapter Four and it was determined that social costs for natural gas, wind, nuclear refurbishment and new nuclear generation will be evaluated. In this chapter, steps 2 through 5 will be carried out to assess the social costs of each generation alternative. In step 2, the private costs of each generation alternative are assessed using a LUEC analysis and in step 3 the computable external burdens are identified, quantified and monetized. Next, the private and external cost estimates are aggregated to arrive at social costs for each generation alternative and the social cost estimates are analyzed to determine the capacity expansion plan to meet the supply gap at the lowest social costs in step 4. Finally, the results of the sensitivity analysis are described in step 5.

5.2 Step 2: Private cost assessment

5.2.1 Natural gas

5.2.1.1 Capital costs

Capital expenditures associated with natural gas-fired electricity generation are categorized as construction and development of the generating unit and construction and development of transport infrastructure.

5.2.1.1.1 Generating unit

Facility capital costs presented in Figure 5-1 are expressed in overnight terms. The average of the six estimates amounts to \$846/kW, which is the figure included in the LUEC analysis. Although most of the estimates represented in Figure 5-1 were based on the cost of building new natural gas-fired generation, the cost associated with converting existing coal-fired generators to natural gas, which may occur in Ontario to some extent, is considered to be of a similar order of magnitude (DSS for MOE, 2005).

Figure 5-1: Natural gas generating unit capital costs

Source	Ayres et al. (2004)	DSS for MOE (2005)	Navigant (2005)	OPA (2005)	Diener (2001)	IEA & OECD NEA (2005)	Average
Capital costs ($/kW)	758	704	911	865	893	944	846

Construction of natural gas-fired generating units is expected to take two years. Costs are assumed to be spread evenly over this period (i.e. 50% in year -2 and 50% in year -1 (Ayres et al., 2004).

5.2.1.1.2 Infrastructure costs

It is likely that the province's existing transport infrastructure network will need to be enhanced to accommodate increased natural gas demand in Ontario (OEB, 2005). Currently, there is 239.8 million Mcf of storage capacity concentrated near the Dawn hub with approximately 19 million Mcf more already in development (OEB, 2005). The Ontario Energy Board's (2005) evaluation of pipeline and storage infrastructure costs with respect to increased natural gas demand in Ontario reveals that infrastructure costs are expected to rise depending on the level of demand.[96] Using data from OEB (2005), infrastructure upgrade costs have been interpolated as necessary and such costs are illustrated in Figure 5-2.[97] Although cost increases are expected to rise incrementally, the base case LUEC analysis is presented using an infrastructure cost of $138/kW, which corresponds to an increase of 5,265 MW of natural gas-fired capacity.[98] It is also noted

[96] It is noted that the scope of the OEB (2005) was focused exclusively on the costs associated with the replacement of coal-fired generation by 2012. Actual costs will depend on a number of factors including the actual increase in demand, the location of the source of gas, the location of the storage facilities and the location of the generating units, as well as other geographical constraints.

[97] OEB figures are based on the average between the low and high estimates for each scenario. For example, the figure for the mid-level OEB scenario estimate (5,265 MW) is derived by the following calculation: [$525 million (low-end) + $930 million (high-end)]/2 = $728 million/5,265,000 kW = $138/kW.

[98] It is acknowledged that it would be more appropriate for the LUEC to reflect the different infrastructure cost levels depending on the level of natural gas-fired installed capacity that is added. However, the cost difference on a per kWh basis between the lowest infrastructure cost and the highest infrastructure cost is approximately $0.001, so for conciseness only the $138/kW infrastructure cost is shown.

that infrastructure upgrades could be expected to come online by 2012 (it is assumed that this cost would be incurred at such time for the purpose of this assessment (OEB, 2005)).

Figure 5-2: Natural gas infrastructure costs

Capacity increase (MW)	0	1,500	3,000	4,305	5,265	6,775
Expected cost ($/kW)	0	37	74	106	138	168
Data source	Assumed	Interpolated	Interpolated	OEB	OEB	OEB

5.2.1.2 Operations and maintenance costs

The four studies in Figure 5-3 provide data for O&M costs associated with natural gas-fired electricity generation. The average fixed cost of $16.23/kW and variable cost of $0.00317/kWh are included in the LUEC analysis.[99]

Figure 5-3: Natural gas operations and maintenance costs

Study	Ayres et al. (2004)	Navigant (2005)	OPA (2005)	DSS for MOE (2005)	Average
Fixed O&M ($/kW)	16.40	16.39	16.39	15.74	16.23
Variable O&M ($/kWh)	0.00327	0.00312	0.00270	0.00357	0.00317

5.2.1.3 Fuel costs

Fuel costs are generally acknowledged as the largest segment of private costs for natural gas-fired electricity generation (Naini et al., 2005). Since the commodity price of natural gas has been unstable for the past decade, determining the future price with a great degree of accuracy is a difficult task. Therefore, expert price forecasts should be interpreted with care as they have not been and are not likely to be exact. Adding to the forecasting complexity is that different analysts hold disparate assumptions regarding various supply and demand factors that affect the price of gas. In addition, natural gas fuel costs must also account for several peripheral costs in addition to the commodity price. Such costs

[99] Other studies (e.g. Diener, 2001) show O&M costs only as a variable cost. When this is the case, the variable costs are higher than the variable O&M costs in the studies presented in Figure 5-3 (e.g. $0.0054/kWh in Diener, 2001), which would seem to account for the fixed portion of the O&M costs that have been explicitly measured here.

include transportation, storage and distribution from the wellhead to the point of consumption as well as price volatility.

Like other commodities, the price of natural gas is a function of a number of factors that influence supply and demand. Ontario is part of an integrated North American marketplace for natural gas, with infrastructure, pipelines and supply arrangements linking producers and consumers throughout Canada and the U.S. Consequently, supply and demand, and thus, the price of natural gas in Ontario, is determined by factors that affect all North American jurisdictions and not just by developments within the province (IEA, 2004).

On the supply side, the size of the existing North American resource base, in combination with current production rates, is a key determinant of the price of natural gas. According to NRCan (2006), it is estimated that there are 2,214 trillion cubic feet (Tcf) of total remaining natural gas resources in North America, with 594 Tcf and 1,620 Tcf estimated to be remaining in Canada and the United States, respectively, including proved reserves, discovered resources and undiscovered resources.[100] If 2004 production levels were to remain constant, Canada would have approximately 100 years of natural gas supply left, while the U.S. would have roughly 86 years before its domestic supply ran out (NRCan, 2006).

Isolating proved reserves, however, can be a more indicative measure of availability over the short-to-medium-term. At the beginning of 2004, proved reserves in Canada were 56.6 Tcf, which was a decrease of 4% from the previous year, compared to the US, which exhibited an increase of proved reserves of 2% from the previous year to 189 Tcf. The

[100] Proved reserves are defined as the "estimated quantities of gas in known drilled reservoirs, which are near existing pipelines and markets. Gas volumes are known with considerable certainty to be recoverable in future years under existing technological and economic conditions". Discovered resources are the "Estimated quantities of gas in known drilled reservoirs, which are too remote to be connected to existing pipelines and markets. If pipelines were built, gas volumes would be recoverable under existing technological and economic conditions", whereas undiscovered resources are "An estimate, inferred from geological data, of gas volumes thought to be recoverable under current or anticipated economic and technological conditions, but not yet discovered by drilling" (NRCan, 2006, p. 9). Data provided in NRCan (2006) are relied upon for this section of the analysis. These figures are generally consistent with other forecasts including BP (2006) and EIA (2006a).

current reserve-to-production (R/P) ratio is approximately 10 years in both Canada and the U.S. (NRCan, 2006). Most of Canada's proved reserves are concentrated within the Western Canadian Sedimentary Basin (WCSB), the majority of which are located in the province of Alberta.[101] Approximately half of WCSB production is shipped to the U.S. market, which meets 15% of total U.S. gas requirements (3.1 Tcf of the 5.7 Tcf produced in Canada in 2004). As the WCSB continues to mature, the Canadian R/P ratio has declined correspondingly, falling from approximately 37 years in 1986 to its current level of approximately 10 years (NRCan, 2006). EIA (2006b, p. 6) claims that "[e]ven though there have been some new conventional natural gas finds in the WCSB, many analysts predict that conventional natural gas production in the WCSB has reached its zenith". A similar trend is observed for conventional reserves in the U.S. as well, where domestic production in 2004 from the Gulf of Mexico (56%) and the U.S. Rockies (23%) accounted for the majority of U.S. supply requirements in addition to that originating from the WCSB (NRCan, 2006; EIA, 2006a).

According to NRCan (2006, p. v):

> Reserve trends are a powerful indicator of future production. In the past, reserve additions greater than production have signalled future production increases. Reserve additions in recent years have approximately equalled or have been lower than production, signalling flat supply for the medium term.

The diminishing success rate of holes drilled throughout North America provides evidence that conventional reserves are on the decline. Indeed, maintaining the same level of reserves requires a higher drilling rate than the previous year. Drilling rates reached a Canadian record in 2004 with 15,627 gas wells drilled. However, despite this 15% drilling increase over 2003, production increased by only 0.5% to 5,906 billion cubic feet (Bcf). Similarly, in the U.S., production of conventional reserves declined by 1% even as the amount of wells drilled rose by 15% in 2004. Experts expect this development to continue in North America in the future (NRCan, 2006).

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[101] The Western Canada Sedimentary Basin is comprised mostly of Alberta, but also includes segments of British Columbia, Saskatchewan, Manitoba, Northwest Territories and Yukon (IEA, 2004). Alberta alone is responsible for approximately 80% of total current natural gas production in Canada (NRCan, 2006).

While an advancement in the technology or the method used to extract natural gas from the ground may be able to increase the drilling success rate in the future, market analysts expect the decrease in North American conventional natural gas output to be "more than offset" by an increase in supply from new conventional sources in Alaska and the Mackenzie Delta region and, to an even greater extent, by unconventional supply sources like coal-bed methane, shale gas and especially liquefied natural gas (LNG) (EIA, 2005).[102] However, these sources are not expected to provide a significant increase in supply over the short term (i.e. before 2007 at the earliest) (OPA, 2005).[103] For the purpose of this study, however, it is assumed that between anticipated conventional and unconventional sources of natural gas, there will be a sufficient amount of gas available for the complete operating lifetime of a new natural gas generation facility without jeopardizing reliability in the electricity system. This is supported in other studies like

[102] LNG, though still in the nascent stages of development, is expected to make up a significantly greater portion of North American natural gas supply in the medium-to-long-term (NRCan, 2006). LNG refers to the process of liquefying natural gas and then re-gasifying it once it has been transported. "When natural gas is chilled to a temperature of about minus 160° C (or minus 260° F) at atmospheric pressure, it becomes a clear, colourless, and odourless liquid[…]As a liquid, natural gas is reduced to one six-hundredth of its original volume, which makes it feasible to transport over long distances in specially designed ocean tankers for storage, re-gasification and delivery to markets" (NRCan, 2005a). Currently, Canada does not have any LNG ports, but is expected to add several in the medium-term, while the U.S. currently has four receiving terminals that account for 1%-2% of total North American natural gas supply (NRCan, 2006). According to the OPA, "At the end of 2004 there were 8 LNG import terminals being proposed for Canadian sites, totalling 4.91 Bcf/d in send-out capacity. The start dates for these terminals range from 2007 to 2009, but only two had received provincial-federal environmental approval as of August 2004" (OPA, SMAR section 3-9, 2005, p. 8). It is anticipated that LNG will constitute 20 Tcf, or 6.4%, of natural gas supply in North America by 2020 (NRCan, 2006). Trinidad and Tobago is currently the largest supplier of LNG to the U.S., but in the future gas may be shipped from places like Brazil, Russia or the Middle East, which have significant reserves. Once LNG is more fully developed, it is expected to have a dampening effect on the North American price of natural gas because it will significantly expand the resource base (OPA, 2005). However, analysts note that despite the fact that emerging economies are poised to increase production by roughly 4% annually to 2025, since several emerging countries (e.g. China and India) are also expected to significantly increase their consumption of natural gas, it remains a possibility that rising global demand for natural gas could end up raising the price in international markets (EIA, 2005).

[103] NRCan's assessment of other prominent forecasts "shows a 'consensus' that both Mackenzie Delta and Alaska natural gas will arrive, but there is disagreement amongst observers regarding the timing of when this natural gas will begin to flow" (NRCan, 2006, p. vii). It is worth mentioning that various pundits in the media have speculated that these supplies of natural gas will be specifically earmarked for the Alberta oil sands, where resource extraction and oil production processes consume a significant amount of natural gas (for example, Reguly in *The Globe and Mail*, 2006). Alberta oil sands production currently consumes 225 Bcf annually. However, significant investment in oil sands production stands to increase this output substantially over the medium term (NRCan, 2006). Both EIA (2006a) and NRCan (2006) forecasts expect Canadian exports to the US to decline in the future as the US obtains a larger share of supply from LNG, which would pave the way for Canada to re-allocate a larger percentage of supply to domestic consumption including oil sands production. However, a significant increase in Canadian domestic demand above the already expected increased level may contribute to a rise in the price of natural gas in North America in the future.

ExternE (Rabl et al., 2005, p. 17), which states that, "[t]here appears to be no problem of scarcity even in the long term and conventional reserves should be sufficient at least until 2035-40".

In addition, some other factors that may influence the price of gas on the supply side are pipeline and storage capacity (which is discussed further below); supply shocks such as natural disasters (e.g. the impact of Hurricane Katrina on Gulf of Mexico natural gas production); and the price of oil (as oil and gas extraction projects are often undertaken together) (NRCan, 2006).

Demand for natural gas is similarly affected by a considerable number of variables. In general, extreme weather, population and economic growth, and the rising price of oil (which can be a substitute for gas) are likely to cause demand for natural gas to increase. On the other hand, effective conservation and demand-side management initiatives, and/or environmental policies such as the Kyoto Protocol will tend to have a diminishing effect on the demand for gas (NRCan, 2006). In 2004, North American demand was 25.3 Tcf, which is an increase of 0.3% above 2003. From 2005 to 2020, demand is expected to rise by roughly 1% per year to a total of 32.5 Tcf by 2020 (NRCan, 2006).

Since 1999, the price of natural gas in North America has gone up significantly due to a tightening of supply and demand. This trend is observed for both the AECO price,[104] which is Canada's benchmark point of reference and the Henry Hub price in Louisiana quoted on the NYMEX, which is America's key measure.[105] From 1991 to 1999, the AECO price remained low at an average price of $1.59/Mcf in nominal terms. From 2000 to 2004, the price climbed to an average of $5.37/Mcf. According to market analysts, the higher price range is likely to be sustained. NRCan (2006, p. ii) notes that:

> North America's natural gas market has entered a new era. Higher natural gas prices, which are now seen as a feature of the natural gas market, at least over the

[104] The AECO price is the wholesale spot price of natural gas produced in Alberta and is also referred to as the Inter-Alberta or NIT price.
[105] The AECO price is expressed in Canadian dollars per gigajoule ($/GJ), while the NYMEX is quoted in US dollars per thousand cubic feet ($/Mcf), or million British Thermal Units ($/MMBtu). One Mcf is equal to one MMBtu, which is equal to 1.055 GJ. Conversely, one GJ is equal to 0.948 Mcf (NRCan, 2006).

medim- term, primarily reflect the inability of North American natural gas production to keep pace with ever-increasing demand.

In 2004, the average price was $6.18/Mcf with a range of $5.69/Mcf to $7.11/Mcf. In the U.S., the NYMEX price, which generally corresponds with the AECO price, experienced an average price of U.S. $6.30/Mcf during this period (NRCan, 2006).[106]

Various analysts believe that while prices are not expected to drop to pre-1999 levels during the planning horizon of this assessment, they are expected to either stabilize or decline slightly. This is due to the increase in new conventional and unconventional supply and to the pace of future demand, which is expected to increase, though at a slower rate than has been observed over the past decade (NRCan, 2006). However, due to the complexity and uncertainty associated with future production and consumption variables, analysts' projections for the price of natural gas are somewhat divergent (refer to Figure 5-4 for various prominent natural gas price forecasts).[107]

[106] It is noted that a NYMEX-Alberta price gap of $0.55/Mcf is typical (NRCan, 2006, p. 14).

[107] It is acknowledged that unexpected developments may shift the price in the future to a level that is higher or lower than experts' predictions. An unexpected supply disruption or a "dash for gas" by North American consumers would drive the price of gas higher, while an unforeseen increase in supply or a reduction in demand could diminish the price in the future. The OPA concedes that "The precise extent to which gas prices will rise or fall in the future is unknown" (OPA supply mix advice report, section 2-5, 2005, p. 24).

Figure 5-4: Natural gas price forecasts (all figures are expressed in $/Mcf)

Forecast	2015	2025	2030
EIA Annual Energy Outlook 2006	5.19	6.24	6.80
Global Insight Inc.[a]	5.44	5.19	5.34
Energy & Environmental Analysis Inc.[a]	6.79	7.41	n/a
Energy Ventures Analysis Inc.[a]	6.36	6.98	7.49
PIRA Energy Group[a]	6.38	n/a	n/a
Deutshe Bank AG[a]	5.78	5.78	5.77
Strategic Energy & Economic Research[a]	5.34	5.90	6.23
Altos Partners[a]	4.77	6.52	7.24
Ontario Power Authority 2005	8.23	8.23	n/a
Navigant Consulting 2005[b]	6.27	6.22	n/a
Natural Resources Canada 2006[c]	4.96	n/a	n/a
Average	6.00	6.35	6.48
Maximum	8.23	8.23	7.49
Minimum	4.77	5.19	5.34

a Forecast data obtained from the EIA Annual Energy Outlook (2006a)

b Navigant (2005) utilized the price of natural gas futures in its forecast, as opposed to all other estimates that evaluated natural gas supply and demand fundamentals.

c Original estimate was converted from GJ to Mcf at the conversion rate of 1 GJ = 0.9478672 Mcf

The commodity cost for natural gas that is incorporated into the LUEC analysis is based on two forecasts. Since most of the gas used in Ontario comes from the WCSB, the NRCan (2006) forecast, which reflects the AECO price, is utilized as it is appropriate for the context of this evaluation. NRCan (2006) cost figures have been adjusted for inflation and converted into $/Mcf. However, since it only runs until 2020, the forecast by EIA (2006a) is relied upon thereafter. EIA (2006a) is highly regarded, and is one of the data sources upon which NRCan bases its estimate (NRCan, 2006). All data points between 2020 and 2030 have been interpolated based on EIA (2006a) estimates for 2025 and 2030. From 2031 to 2034, which is the last year of the operating life of the generating unit, costs are assumed to rise by 1% each year. It is noted that fuel costs are reduced after 2020 by \$0.55/Mcf to account for the typical price differential between AECO and NYMEX values (NRCan, 2006).

A key consideration for the LUEC analysis is whether the increase in natural gas-fired generation in Ontario will be expected to have a sizeable impact on total North American consumption beyond what is already considered in analysts' forecasts, and hence, whether this would have an appreciable impact on the future price of natural gas. On an annual basis, the Ontario market consumes roughly 948 million Mcf of natural gas, the majority of which is sent to Dawn from the WCSB (OEB, 2005). Current consumption per unit of natural gas-fired generation is calculated to be 3.4 million Mcf per year, which amounts to 0.4% of the total amount of natural gas consumed on average in Ontario per generating unit.[108] Since existing units are used for peaking and intermediate generation, and the potential capacity expansion evaluated in this assessment assumes that natural gas-fired generating units will be used to generate base-load electricity, it is assumed that the marginal consumption per unit will have a capacity factor that is 58 percentage points higher than that of existing units.[109] Consequently, current consumption per generating unit would increase by 332%.[110] Therefore, each additional natural gas-fired generating unit is expected to increase total natural gas consumption in Ontario by 1.2% up to a maximum increase of 16.6%.[111] In relation to the total amount of North American consumption (which is more relevant for determining the effect on the price of natural gas), however, the maximum increase in total North American natural gas consumption

[108] Calculation: 0.006967 Mcf/kWh (average amount of natural gas consumed per kWh) x 11 TWh (amount of natural gas consumed by natural gas-fired generation in 2005) = 76,637,000 Mcf. Since 20 generating units were active, the average consumption of each unit was: 76,637,000 Mcf / 20 = 3,381,850 Mcf per natural gas-fired generating unit (OPA, 2005; IESO, 2005). Expressed as a percentage of total natural gas consumption in Ontario the calculation is: 3,381,850 Mcf / 948,000,000 Mcf = 0.40%

[109] Calculation: 11 TWh (natural gas-fired consumption in 2005) / 4,976,000 kW (installed natural gas capacity in 2005) x 8,760 (number of hours in a year) = 25% (2005 average capacity factor in Ontario). Since the average capacity factor of natural gas generating units is estimated to be 83% in this assessment (as is discussed in section 5.2.1.4.2), the average capacity factor should be increased by 58 percentage points to account for the increased consumption of gas per marginal generating unit.

[110] Calculation: 83/25 = 332%

[111] Calculation: 3,381,850 Mcf x 3.32 = 11,227,742 Mcf. Expressed as a percentage of total natural gas consumption in Ontario: 11,227,742 Mcf / 948,000,000 Mcf = 1.2%. Since each unit is assumed to have a capacity of 500 MW (which is discussed further in section 5.2.1.4.1.) and the forecasted supply gap is 7,000 MW, a total amount of 14 new natural gas generating units may be added to the supply mix. Therefore, 1.2 % x 14 = 16.6%

resulting from a scenario in which the 7,000 MW supply gap in Ontario is filled entirely by natural gas-fired generation is 0.616%, which is considered to be negligible.[112]

In addition to the charge for the commodity itself, various other costs associated with the transport and distribution of gas from the WCSB to Ontario and the storage of the gas need to be reflected in the net fuel cost (OEB, 2005). Based on the conventional price difference between AECO and Dawn, it is reasonable to add another $1.00/Mcf to the AECO price to account for transportation costs to Ontario (NRCan, 2006). (This cost is assumed to be $0.15 when the EIA (2006a) fuel cost estimates are included based on the price differential between Henry Hub and Dawn (NRCan, 2006).) Furthermore, Diener (2001) (which utilizes data from Union Gas) notes that storage and distribution costs from the Dawn hub to the province's natural gas-fired generating units amount to $0.34/Mcf.

In addition, the cost associated with the volatility in the price of natural gas is considered as well. As previously discussed, due to the complexities associated with natural gas supply and demand, forecasting the price remains speculative, at best. Since the rise in the price of natural gas in the late 1990s, such price movement has also exhibited a considerable level of volatility, which is the extent to which the price has diverged from the mean. There have been three instances since 1995 when the price has spiked noticeably due to extreme cold spells in the winter and lower than average storage levels, in addition to the frequent smaller price fluctuations that are considered commonplace (Naini et al., 2005). This inherent uncertainty carries a cost: when the price is highly volatile, it is a poor indicator of future prices, and the uncertainty provides a disincentive for business investment and may also disrupt household spending patterns (Bolinger et al., 2002). Consequently, large consumers who are accustomed to such volatility mitigate

112 Calculation: 11,227,742 Mcf (assumed consumption of marginal natural gas-fired generating units in Ontario) / 25,300,000,000 Mcf (North American consumption in 2004) = 0.044%. Therefore, 0.044% x 14 = 0.616%.

their risk through employing financial instruments that hedge volatility risk.[113] Bolinger et al. (2002) show that such costs to natural gas consumers are \$0.006/kWh.[114]

Therefore, the net fuel cost is equal to the commodity cost plus costs associated with transportation, storage, distribution and volatility. When NRCan (2006) commodity cost figures are used (until 2020) this results in an additional \$1.35/Mcf[115] to net fuel costs per year and when EIA (2006a) commodity figures are used \$0.50/Mcf[116] is added to net fuel costs per year.

5.2.1.3.1 Heat rate

To determine the annual fuel costs per kWh, the heat rate must also be known. The heat rate is the amount of energy that is emitted when a fuel source is used for electricity generation at the point of its conversion into electricity. Such a measure of thermal efficiency is expressed in terms of thousand cubic feet per kilowatt-hour (Mcf/kWh). Various heat rates used in previous studies are presented in Figure 5-5 and the average, 0.006967 Mcf/kWh is used.

Figure 5-5: Natural gas heat rate

Source	Diener (2001)	Navigant (2005)	Ayres et al. (2004)	DSS for MOE (2005)	Average
Heat rate (Mcf/kWh)	0.006770	0.007100	0.007000	0.007000	0.006967

113 Examples of financial derivatives include swaps (an arrangement where two parties swap a fixed price for a variable spot price for a specified term period), futures (which allows market participants to lock in at a particular price up to six years in advance) and options (which give the option holder the right but not the requirement to buy or sell a futures contract at a specified price at a specified date in the future in return for a premium). In addition to financial hedging, consumers may enter into long-term fixed supply contracts, as for example, OPG does (OPG, 2006a).

114 The results of Bolinger et al. (2002) were based on the hedge value of 10-year swaps, which carry a premium in relation to future natural gas price forecasts.

115 Calculation: \$1.00/Mcf (transportation cost) + \$0.34/Mcf (storage and distribution cost) + \$0.01/Mcf (price volatility cost) = \$1.35/Mcf

116 Calculation: \$0.15/Mcf (transportation cost) + \$0.34/Mcf (storage and distribution cost) + \$0.01/Mcf (price volatility cost) = \$0.50/Mcf

Based on the net fuel cost and heat rate data, natural gas fuel costs are derived on a per kWh basis. The calculation is expressed by the following equation:

Fuel cost ($/kWh) per year = net fuel cost ($/Mcf) x heat rate (Mcf/kWh).

Since net fuel costs fluctuate every year, natural gas fuel costs per kWh are different in every year of the analysis. For illustration purposes, the fuel cost in the first year of the natural gas generating unit's operating life is $0.0490/kWh.[117]

5.2.1.4 Natural gas planning assumptions

5.2.1.4.1 Generating unit capacity

The OEB (2005) notes that the average of the last 11 natural gas-fired electricity generation facilities built in Ontario is 457 MW. After accounting for the two most recently announced natural fired generation units that were not included in that review (Goreway, 875 MW and Portlands, 550 MW, respectively), an average capacity of 500 MW is assumed.

5.2.1.4.2 Average capacity factor

Average capacity factors that were used in five prominent studies are presented in Figure 5-6, and the average, 83%, is included in this analysis.

Figure 5-6: Natural gas average capacity factor

Source	Ayres et al. (2004)	IEA & OECD NEA (2005)	OPA (2005)	Diener (2001)	DSS for MOE (2005)	Average
Average capacity factor (%)	90	85	85	65	90	83

[117] Calculation: $7.04/Mcf (net fuel cost) x 0.006967 Mcf/kWh (heat rate) = $0.0490/kWh

5.2.1.4.3 Operating life

The range of operating lifetimes for natural gas-fired generating units in the studies presented in Figure 5-7, is 20 to 40 years. The average operating life is 27 years, which is incorporated into the LUEC analysis.

Figure 5-7: Natural gas operating life

Source	Ayres et al. (2004)	IEA & OECD NEA (2005)	Diener (2001)	DSS for MOE (2005)	Average
Operating life (yrs)	30	40	25	22	27

5.2.1.4.4 Discount rate

Private costs are evaluated under two scenarios. First, costs are assessed using a 5% public discount rate as discussed in section 4.2.2. Then, a merchant discount rate of 13% is applied, based on the cost of equity for an all-equity project. Discount rates are expressed in real terms and are presented in Figure 5-8.

Figure 5-8: Natural gas discount rate

Perspective	Public	Merchant
Discount rate (%)	5	13

5.2.1.5 Total private costs of natural gas-fired generation

Based on the private cost figures and planning assumptions selected, the private costs associated with natural gas-fired electricity generation on a LUEC basis are \$0.060/kWh from a publicperspective and \$0.076 under the merchant perspective.[118]

[118]Refer to Appendix C (i and ii) for LUEC calculations.

5.2.2 Wind

5.2.2.1 Capital costs

The majority of capital expenditures relates to producing and erecting wind turbines, but also includes feasibility studies, development and engineering costs and balance of plant costs (e.g. regarding foundation, roads, electronics, etc.) (Retscreen, 2006). Turbine construction includes the manufacture and assembly of the base, tower, blades and nacelle (which house the drive train, generator and gearbox) (NEB, 2006). Turbine cost figures obtained from several reports are presented in Figure 5-9.[119] The average of the five estimates comes to $1,845/kW, which is included in the LUEC analysis.[120]

Figure 5-9: Wind generating unit overnight capital costs

Source	ONWPTF (2002)	OPA (2005)	Mindorff in Naini et al. (2005)	Hornung in Naini et al. (2005)	NEB (2006)	Average
Capital costs ($/kW)	1,652	1,968	1,954	1,954	1,700	1,845

Construction of wind-powered generating units is expected to take two years. Costs are assumed to be spread evenly over this period (i.e. 50% in year -2 and 50% in year -1).

[119] These estimates are generally consistent with recently announced wind projects in Erie Shores, Ontario (99 MW, capital cost of $186 million = $1,880/kW) and Melancthon Grey, Ontario (67.5 MW, capital cost of $120 million = $1,780/kW) (Naini et al., 2005).

[120] It is noted, however, that wind capital costs have declined over the past two decades and are expected to continue to decrease in the future as turbines increase in size, develop more standardized parts and increase economies of scale (NEB, 2006). IEA (2000) notes that while the technical components used in wind turbines have reached maturity, there may still be considerable room for improvement due to increased turbine sizes and considerable learning potential with respect to siting techniques, which would allow the cost per unit of output to improve. One obstacle that could conceivably hinder the downward trend in price is the rising cost of steel (Naini et al., 2005). However, despite this recent cost increase, it is assumed that capital costs in real terms will decline somewhat over the medium-to-long-term. However, since the magnitude of such a future cost reduction is uncertain, the current state of knowledge reflecting a capital cost of $1,845/kW is assumed to be appropriate.

5.2.2.2 Costs associated with transmission and distribution integration and balancing[121]:

Besides turbine investment costs, wind-powered electricity generation carries additional costs due to its intermittent nature.[122] Helimax for CanWEA (2005, p. 12) notes that intermittency may have disruptive implications with respect to planning for "load following, operating reserves, reactive power requirements, voltage control, frequency regulation, etc." in the electricity system. Consequently, some expenditure may be necessary to enhance the transmission and distribution network and/or add back-up power to balance wind power fluctuations even below the threshold of total installed capacity noted earlier (OPA, 2005; NEB, 2006). Such costs are generally site-specific (NEB, 2006), depending on factors like the level of capacity that is being installed, power line voltage, and the location of the potential generating units in relation to the load and the grid (Helimax for OPA, 2005). According to Howatson and Churchill (2006, p. i), "methodologies for estimating costs of integration have not been standardized, estimates vary, and further research is required." Nevertheless, Hydro-Quebec has estimated that such integration and balancing costs are, on average, \$0.005/kWh and this figure is adopted for the purpose of the LUEC analysis (NEB, 2006).[123]

5.2.2.3 Operations and maintenance costs

Wind-powered electricity generation is highly reliable with a 98 percent availability rate (when the wind is blowing sufficiently), requiring only approximately 40 hours per year of maintenance, which is the best performance among the generation alternatives under

[121] In the literature, these costs are usually grouped together. Although balancing costs may not be capital costs per se, they are discussed in this section to be consistent with the literature.

[122] However, it is noted that other generation alternatives could also theoretically be assigned such a cost to some extent due to planned and non-planned outages, but this type of cost is assumed to be more prevalent with respect to wind power because of wind fluctuation. According to Lovins (2005, p. 7), "Every source of electricity is intermittent, differing only in why they fail, how often, how long, and how predictably".

[123] It is assumed that Hydro-Quebec will utilize large-scale hydropower to balance wind intermittency. NEB (2006, p. 15) notes that "Hydro and wind systems have a natural synergy. Hydro units can vary their output quickly, compensating for changes in wind generation. Wind power can be a useful supplement, providing energy when the wind blows, allowing hydro facilities to save water for future generation". However, it is uncertain whether the electricity system in Ontario would utilize hydro or another generation alternative such as natural gas. Given that the literature is limited in this area, it is assumed that the \$0.005/kWh cost estimated by Hydro-Quebec is appropriate for the Ontario context, although future research would be beneficial.

study (OPA, 2005). According to Hornung (in Naini et al., 2005), the costs associated with operations and maintenance for wind-powered electricity generation are approximately \$0.015 per kWh, which is incorporated into this assessment.[124]

5.2.2.4 Fuel costs

Since wind power is a natural, renewably-generated resource, fuel costs associated with wind-powered electricity generation are nil. However, turbines must be located at sites with sufficient average wind speed in order to be productive (i.e. superior wind speed will generate more electricity than poor wind speed, *ceteris paribus*) (Helimax for OPA, 2005). The European Wind Energy Association (2003, p. 97) notes that, "[a]s electricity production is highly dependent on wind conditions, choosing the right site is critical to achieving economic viability". According to the OPA (2005), as a general rule, the average speed at which wind power may become competitive with other electricity generation sources is 6.5 metres per second (m/s) at a tower height of 80 metres above the ground. Moreover, as wind speeds increase, wind electricity output rises in a non-linear fashion. For example, a twofold increase in average wind velocity will produce an eightfold increase of electricity output (Naini et al., 2005). Thus, it is assumed that all wind-powered electricity generation capacity added to the Ontario supply mix will possess a minimum average wind velocity of 6.5 m/s. Since the level of installed wind capacity comprises less than one percent of the supply mix as currently constituted there is significant room for wind growth in Ontario at this minimum wind speed requirement (OPA, 2005).

However, potential turbine locations must exhibit other favorable qualities in addition to sufficient average wind speed if they are to be developed and several physical and social constraints may prohibit such development. First, it is likely that wind farms will be sited within close proximity of the existing transmission network, which disqualifies most northern regions in Ontario that are thought to possess excellent wind resources, but which are located at a considerable distance from the grid (Helimax for OPA, 2005).

[124] This figure is generally consistent with O&M costs found in ONWPTF (2002) and OPA (2005), which are expressed on a fixed cost basis.

NEB (2006, p. x) states that, "[e]conomic access to existing transmission facilities is often a decisive factor for project siting and feasibility". Similarly, even in regions that are close to the grid, transmission and distribution upgrades depending on the configuration of the grid at the local or regional level may prevent a potential wind site from being developed. Moreover, local topography restrictions must also be taken into consideration. Besides physical impediments, social barriers may prevent the development of wind-powered electricity generation, including zoning regulations and social acceptability concerns (which are discussed further in section 5.3.2.3.3). Given these constraints, it has been estimated that roughly 7,000 MW to 9,000 MW of technical onshore wind potential exists in Ontario (Helimax for OPA, 2005).[125] This level of potential wind capacity is large enough to accommodate 15% of the installed supply mix, which has been identified as a threshold beyond which reliability in the electricity system may be compromised (OPA, 2005).[126]

5.2.2.5 Wind planning assumptions

5.2.2.5.1 Generating unit capacity

Turbines come in various sizes depending on power requirements. New on-land wind farms generally employ turbines that have a capacity of roughly 2 MW compared to 1980s technology, which had a capacity of around 20-60 kW and 1990s technology that had a capacity of approximately 500kW to 1 MW (Naini et al., 2005). Two of the more recent wind farms to come online in Ontario were in Kingsbridge and Melanchton-Shelburne. These farms utilized individual turbines with a capacity of 1.8 MW and 1.5

[125] Helimax for OPA (2005) estimates wind potential by converting land mass into MW capacity by using a conversion ratio of 5 MW for each km^2. Potential wind sites with an average wind speed of 6.5 m/s or greater at a height of 80 metres, located either within 10 km of existing transmission lines or within 5 km of the distribution network, were considered to be within a feasible distance for wind development to occur. In addition, potential wind sites are not constrained by hydrography, roads, railroads, slopes, buildings, important bird areas and provincial and national parks (all including buffer zones). As this was a preliminary assessment, however, a more detailed investigation involving actual voltage and the capacity of transmission and distribution to integrate wind power would be necessary before construction could take place. It is also noted that the wind potential estimate does not account for social acceptability concerns.

[126] Refer to section 4.2.4.1 for a discussion on this issue.

MW, respectively (MOE, 2006b). Consequently, turbines with a capacity of 1.8 MW are assumed for this analysis.[127]

5.2.2.5.2 Average capacity factor

Capacity factor is a "key determinant" of the costs associated with wind-powered electricity generation on a per kilowatt hour basis (NEB, 2006). AWS (2005) finds that the average capacity factor of wind turbines in Ontario is significantly higher in the winter (47%) than it is in the summer (19%). However, the average capacity factor for the entire year is of particular relevance for this assessment. Figure 5-10 reveals an average of 31% from the studies evaluated. This is consistent with the range of 25% - 40% stated by the American Wind Energy Association (OPA, 2005).[128]

Figure 5-10: Wind average capacity factor

Source	ONWPTF (2002)	OPA (2005)	Hornung in Naini et al. (2005)	NEB (2006)	Average
Capacity factor (%)	32.5	30	30	30	31

5.2.2.5.3 Operating life

The range of operating lifetimes for turbines evaluated in the studies presented in Figure 5-11, is 20 to 40 years. The average operating life is 28 years, which is incorporated into the LUEC analysis.

Figure 5-11: Wind operating life

Source	ONWPTF (2002)	OPA (2005)	Mindorff in Naini et al. (2005)	Hornung in Naini et al. (2005)	NEB (2006)	Average
Operating life (yrs)	27.5	20	40	25	25	28

[127] The size of the turbine does not affect the results of the LUEC, so even if a larger turbine capacity was assumed, the results would not change.
[128] Of course, the actual capacity factor for each individual turbine would be site-dependent.

5.2.2.5.4 Discount rate

The LUEC is evaluated under two scenarios. First, costs are assessed using a 5% public discount rate. Then, a merchant discount rate of 13% is applied, based on the cost of equity for an all-equity project. Discount rates are expressed in real terms and are presented in Figure 5-12.

Figure 5-12: Wind discount rate

Perspective	Public	Merchant
Discount rate (%)	5	13

5.2.2.6 Total private costs of wind-powered electricity generation

Based on the private cost figures and planning assumptions selected, the private costs associated with wind-powered electricity generation on a LUEC basis are $0.067/kWh from the public perspective and $0.158 under the merchant perspective.[129]

5.2.3 <u>Nuclear</u>

Before evaluating the social costs associated with nuclear-fired electricity generation, it is worth mentioning that there are currently two nuclear operators in the province of Ontario and this is expected to continue over the planning horizon. The first, Ontario Power Generation (OPG), is a crown corporation acting as a commercial entity. OPG owns and operates the units at Pickering and Darlington stations and owns the Bruce reactors (OPG, 2006a). The second, Bruce Power, is a consortium of private investors that leases Bruce Nuclear Station from OPG (Bruce Power, 2006a). For the purpose of this assessment, it is assumed that the costs associated with nuclear-fired electricity generation incurred by each entity are the same.[130]

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[129] Refer to Appendix C (i and ii) for LUEC calculations.

[130] However, Bruce Power pays a nominal leasing fee to OPG, but it does not appreciably affect the economics of the evaluation (OPG, 2006a). Other private costs and planning assumptions remain unchanged regardless of which operator's costs are assessed.

5.2.3.1 Capital costs

Capital costs comprise the largest component of the private cost structure for nuclear-fired electricity generation and such costs are dominated by the commissioning of the generating unit (Thomas, 2005). Each nuclear generation facility includes one reactor core (which is where the fissioning process occurs) and 12 steam generators (which physically produce the electricity). Besides expenditures on the equipment and the facility itself, capital costs also include labour construction costs, which can be significant due to the complex engineering expertise required and the relatively long construction period (OPA, 2005).

Once in use, reactors may undergo a refurbishment process to extend their operating lifetimes.[131] In recent years, several reactors in Ontario have undergone such a process and several more are candidates to do so in the future. Since the cost levels associated with the refurbishment of existing reactors and the construction of new nuclear facilities are discrete, these options are evaluated separately in this assessment.

5.2.3.1.1 Nuclear refurbishments

Refurbishment involves the rebuilding of the reactor core, which may include replacement of principal reactor components. This procedure is considered to be beyond routine maintenance and requires units to be taken out of service for anywhere between two and six years (OPA, 2005; Winfield et al., 2004). In Candu nuclear reactors, the key elements of the refurbishment process involve the replacement of fuel channels (a process referred to as “re-tubing”) and other pieces of generation equipment like steam generators. Due to the complexity and the intricate design of Candu technology, re-tubing, which has been described by Winfield et al. (2004, p. 125) as being equivalent to a “heart transplant” for a Candu reactor, can be quite capital and time-intensive.

[131] The estimated length of operating lifetime for each reactor is discussed further in section 5.2.3.6.3.

In Figure 5-13, a few recent historical costs and one contracted cost are included along with several refurbishment estimates from the literature. The average of these figures is $1,922/kW, which is incorporated into the LUEC as the refurbishment capital cost.

Figure 5-13: Nuclear refurbishment capital costs

Source	Epp et al. (2003)	Winfield et al. (2004)	DSS for MOE (2005)	OPA (2005)	Gibbons (2006)	Bruce (2006)	Average
Refurbishment cost ($/kW)	2,496	1,879	1,410	1,846	2,112	1,788	1,922

Nuclear refurbishments are expected to take two years. Costs are assumed to be spread evenly over this period (i.e. 50% in year -2 and 50% in year -1).

5.2.3.1.2 New nuclear generating units

New nuclear reactors have a different capital cost level than that of a refurbishment project.[132] Building a new reactor is a significant technical undertaking and can take approximately 10 to 12 years from start to finish (OPA, 2005). This period may include roughly four to six years for such processes as siting, technology and environmental assessments, procurement initiatives and regulatory approvals. After that, the construction period is estimated to last for approximately six years (Ayres et al., 2004).[133] Figure 5-14 presents various capital cost estimates for new nuclear facilities and the average, $3,003/kW, is used in the LUEC analysis.

[132] As noted in Chapter Four, any new reactors built in Ontario are assumed to be of the Candu 6 variety.

[133] There are costs associated with the lack of operational flexibility that are inherent with the utilization of nuclear power. Due to the long construction time, there is a risk that the plant could be redundant several years into the future if demand is lowered through conservation and demand-side management measures. Moreover, capital intensive generation alternatives that have long construction times such as new nuclear generating units are vulnerable to increased financing costs in the merchant scenario. Thomas (2005, p. 14) notes that, “In a competitive electricity system, long forecast construction times would be a disadvantage because of the increased risk that circumstances will change, making the investment uneconomic before it is completed”. It is unknown what monetary costs, if any, this burden poses, which is acknowledged as a limitation of this analysis.

Figure 5-14: New nuclear generating unit capital costs

Source	Winfield et al. (2004)	Ayres et al. (2004)	OPA (2005)	IEA & OECD NEA (2005)	OPG (2005)	OCAA (2006)	Average
New generating unit capital cost ($/kW)	2,990	3,182	2,935	1,616	3,122	4,173	3,003

In addition, most of the capital cost estimates in Figure 5-14 do not appear to exhibit an appreciation for potential cost overruns, which have historically plagued the construction of nuclear reactors and refurbishment projects in Ontario (Winfield et al., 2004). Due to previous challenges with meeting budgetary requirements and in-service schedules, the capital cost figures incorporated into this assessment can be interpreted as a lower bound.[134]

Construction duration and project cash flows:

Capital costs are expressed as overnight capital costs. Construction of new generating units are expected to take 6 years and costs are assumed to be spread over a 7-year period

[134] In Ontario, the construction of new nuclear reactors and the refurbishment of existing units have had a dismal record of being completed on time and on budget (OPA, 2005; Gibbons, 2006). According to Winfield et al. (2004, p. 126), "Every nuclear power plant built by Ontario Hydro had significant cost overruns". The construction of the Darlington Nuclear Station, which was the most recent nuclear facility in Ontario, experienced significant cost increases and delays. In 1978, the projected cost was estimated to be $4 billion with in-service dates from November, 1985 to February, 1988 (Gibbons, 2004). However, due to a lack of actual engineering data to support the original estimate and a temporary suspension of construction, the actual cost rose by 260% to $14.3 billion, or $4,058/kW. Besides this $10.3 billion increase, the project did not come online until October, 1990 to February, 1993, which was a delay of roughly 5 years (OPA, 2005). After the restructuring of the market in Ontario and the transfer of nuclear assets from Ontario Hydro to Ontario Power Generation and Bruce Power, cost and time overrun problems persisted. The refurbishment of Pickering A unit 4 was expected to cost $457 million and be returned to service in June, 2000. Instead, the actual cost rose by 174% to $1.25 billion and the unit came online in September, 2003 (Epp et al., 2003). Similarly, Bruce A units 3 and 4 were forecast to cost $375 million and ended up costing $725 million and Pickering A unit 1 was originally estimated to cost $213 million and escalated to $1.016 billion (Gibbons, 2006). In addition to the direct costs that are incurred, there are also some indirect costs associated with time overruns. If a generating unit comes online later than expected, it may create a tightening of supply and demand. Electricity may have to be generated from more costly sources or imported from other jurisdictions at a premium, pushing the price of electricity upwards (Thomas, 2005). According to the NEB (2006), this was the case in Ontario recently when delays in bringing nuclear reactors online led to a greater reliance on coal-fired generation.

as follows: 8% down payment in (year -6), 21% (year -5), 27.1% (year -4), 19.6% (year -3), 12% (year -2), 7.2% (year -1), 5.1% (year 1, in operation) (Ayres et al, 2004).[135]

5.2.3.2 Operations and maintenance costs

The four studies included in Figure 5-15 were used to derive the O&M costs for nuclear-fired electricity generation. The average, \$0.01362/kWh, is included in the LUEC analysis for both refurbishment and new build options.[136]

Figure 5-15: Nuclear operations and maintenance costs

Source	Ayres et al. (2004)	DSS for MOE (2005)	OPA (2005)	IEA & OECD NEA (2005)	Average
O&M costs (\$/kWh)	0.01381	0.01322	0.01698	0.01048	0.01362

5.2.3.3 Fuel costs

Candu nuclear reactors utilize natural uranium (which contains 0.7 percent of the uranium isotope U_{235} used in the fission process) for its source of fuel (Naini et al., 2005). Relative to other fuel sources used for electricity generation, uranium has an extremely high energy density. Consequently, uranium is able to generate approximately 10,000 times more electricity per unit mass than other generation alternatives that rely on an

[135] In addition to the time that it takes to construct a new nuclear generating unit, regulatory approvals may take anywhere from four to six years before construction can take place, which is not factored into the cost assessment.

[136] It is noted that O&M costs are lower than they otherwise would be due to artificially reduced insurance costs. The Nuclear Liability Act limits the liability of Ontario nuclear operators in the event of an accident and hence, the cost of insurance is lowered as well. The Nuclear Liability Act outlines the permissible allocation of risks and insurance payments that are shared between nuclear plant operators, insurance companies and the federal government. Nuclear operators' liability is capped at \$75 million for a large-scale accident, after which the Canadian government assumes the remaining costs (*Canadian Nuclear Liability Act*, R.S., 1985, c. N-28). According to the IEA (2004, pp. 150-151), "The limit of nuclear third-party liability to \$75 million in Canada is low by comparison to other western, developed countries and 93% lower than the new minimum limit specified by the Paris Convention on Third Party Liability in the field of nuclear energy." This report further notes that "It is appropriate that the government of Canada reviews and modernises the current legislation on this issue." Although it is known that insurance costs are lower than they would be without the legislation, the magnitude that reduced insurance costs have on total O&M costs is unclear, which is a limitation of this analysis.

equivalent amount of fossil fuel and therefore, a relatively smaller amount is necessary to generate electricity (OECD NEA, 2003a).

Fuel costs are only a minor LUEC component of nuclear-fired electricity generation (due to the aforementioned miniscule uranium requirements and, more significantly, the relative magnitude of nuclear capital costs). However, the availability of uranium resources remains an important consideration for the future prospects of nuclear power. As with natural gas, the uranium market is sensitive to various supply and demand factors. But, while natural gas is, at present, mostly affected by North American supply and demand levels, uranium is an international commodity that is more easily transported to international destinations and, as a result, uranium production and consumption is more a function of market fluctuations at the global level.[137]

According to the "Red Book" compiled by the OECD Nuclear Energy Agency and International Atomic Energy Agency, 4.7 million tonnes of known conventional uranium resources costing \$130 USD/kg or less to extract are estimated worldwide as of January 1, 2005 (IAEA, 2006a). In addition, 35 million tonnes of undiscovered conventional uranium resources are thought to exist, but some portion of this total may not be economically extractable (IAEA, 2006a). Based on the current rate of global demand, this would provide enough supply for approximately 85 years (IAEA, 2006a). MIT (2003) notes that even if there were to be a doubling of nuclear generation today, there would be enough uranium to last for the entire operating life of the new fleet of reactors. Moreover, Prince et al. (2005, p. 70) presume that "for the foreseeable future there appears to be no constraint to nuclear potential imposed by the availability of fuel". Thus, it is assumed that there is enough sufficiently inexpensive uranium to cover the planning horizon considered in this evaluation, especially given that a considerable share of it is located in Canada.

[137] In the future, LNG will cause natural gas to be more sensitive to market factors outside of North America, which has been discussed in section 5.2.1.3.

Half of the world's total known recoverable uranium resources are located in Australia, Canada and the U.S., and Canada alone has roughly 12% of global deposits (Prince et al., 2005; Partridge, 2006). With 444,000 tonnes of recoverable uranium resources located in Saskatchewan as of January 1, 2005, Canada ranks third in the world in terms of largest uranium resources. However, in terms of high-grade deposits, Canada ranks first overall (NRCan, 2005b).[138] The uranium mine at McArthur River in Saskatchewan is renowned as the world's largest high-grade source of uranium (MIT, 2003).

In terms of production, in 2004 Canada ranked first among uranium-producing nations with 11,597 tonnes, which contributed to approximately one-third of total worldwide production (NRCan, 2005b and SENES for OPA, 2005). Only a small fraction of Canadian uranium production, however, is used for domestic purposes, with upwards of 11,000 tonnes exported abroad on an annual basis (IAEA, 2003). At current production rates, Canadian uranium resources are forecasted to last for at least 40 years (SENES for OPA, 2005). Consequently, NRCan (2005b, p. 2) estimates that, "[w]ith over 80% of the resource base categorized as 'low-cost', Canada is well positioned to continue its leadership in uranium production".

Figure 5-16 provides several fuel cost estimates from the literature. The average, \$0.00276/kWh, is incorporated into the LUEC calculations for both refurbishment and new unit nuclear options.[139]

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[138] Recoverable uranium resources include measured, indicated and inferred resources, approximately 80% of which are expected to be mineable for \$50/kg or less. (The remainder are considered mineable at \$100kg or less) (NRCan, 2005b).

[139] However, it is unclear whether each of these estimates has accounted for the recent increase in the price of uranium. Since 2001, uranium prices have increased fivefold (IAEA, 2006). In 2001, uranium was \$7 USD/lb., partially due to the excess supply caused by the dismantling of American and Russian nuclear weapons following the end of Cold War. Since then, the price has climbed to \$37.50/lb (as of the beginning of 2006), as a result of rising nuclear-fired electricity generation in Asia and the growing interest in nuclear power in Western countries in response to concerns about climate change. Experts are forecasting that the price of uranium will be in the range of \$35 USD/lb. to \$70 USD/lb. over the medium-term (Partridge in *The Globe and Mail*, 2006). In any event, since fuel costs make up such a small proportion of the total private costs for nuclear-fired generation, even a doubling of the figure adopted in this analysis would have a negligible impact on social cost estimates.

Figure 5-16: Nuclear fuel costs

Source	Ayres et al. (2004)	DSS for MOE (2005)	OPA (2005)	IEA & OECD NEA (2005)	Average
Fuel costs ($/kWh)	0.00246	0.00188	0.00247	0.00424	0.00276

5.2.3.4 Decommissioning costs

Decommissioning refers to "[t]he act of taking a generating unit or plant out of service permanently" (Ayres et al., 2004, p. 65). To implement the decommissioning process once the reactor ceases producing electricity, three phases will be carried out over a period of approximately 43 years (Ayres et al., 2004). In the first phase, the reactor is shutdown and decontaminated. This is followed by a dormancy period and finally, the components are disassembled and transferred to a repository. In addition, after this process is complete, the site itself is decontaminated (IAEA, 2005). Although decommissioning is undertaken for all other generation alternatives under consideration, the procedure is more complex for nuclear-fired electricity generation since some of the equipment and materials remain radioactive after use and must be disposed of in a similar fashion as that of high-level radioactive waste.[140] As a result, the decommissioning process is more costly for nuclear than for other generation alternatives (i.e. the cost is non-negligible, unlike the other generation options under study) (Ayres et al., 2004).

Determining the cost of decommissioning with accuracy is difficult since it has never been done on a commercial scale (MIT, 2003). Data from previous experience with smaller research facilities are used to estimate the cost. Such estimates are generally thought to be in the range of 15-20% of generating unit construction costs (OECD NEA, 2003a). However, Thomas (2005, p. 32) warns that, "[g]iven that the cost of decommissioning clearly only bears a limited relationship to the cost of construction, this illustrates how little is known of the costs". For this assessment, only two sources of decommissioning costs are available and their average is illustrated in Figure 5-17. This estimate is consistent with IAEA (2005), which notes that the range of decommissioning

[140] Some of the components and materials, however, are low or intermediate-level waste.

costs per reactor is likely to be $210 million to $1,050 million and it is also consistent with the conventional proportion of construction costs cited above.

Figure 5-17: Nuclear decommissioning cost

Source	Ayres et al. (2004)	OPA (2005)	Average
Decommissioning cost ($/kWh)	0.00125	0.00084	0.00105

5.2.3.5 High-level waste management costs

High-level nuclear waste refers to the remnants of uranium that have undergone nuclear fissioning and other waste by-products generated at other stages of the nuclear fuel cycle that are highly radioactive (e.g. mill tailings).[141] Such radioactive waste takes thousands of years to return to the radioactivity found in natural uranium (OPA, 2005). Due to this extremely long half-life, radiological waste must be carefully managed well into the future to mitigate potential human health and environmental impacts. Although waste management has been widely recognized as a key consideration of nuclear-fired electricity generation since entering into commercial operation in the 1970s, a viable long-term solution has yet to be established either in Canada or abroad (MIT, 2003).

To date, Canadian reactors have generated roughly 2 million used fuel bundles or approximately 36,000 metric tonnes of uranium, the majority of which have been produced in Ontario (NWMO, 2005). Nuclear waste is currently stored on an interim basis at the nuclear generating unit where it was produced. For the first six years after being produced the waste is stored in a pool of water and then it is transferred to concrete containers for dry storage. According to AECL (2006a), on-site storage may be acceptable for approximately 100 years, after which time the waste must be relocated to prevent a safety hazard since due to the finite effectiveness of temporary storage containers.

[141] Only management of high-level radioactive waste is evaluated here since the costs associated with managing low and intermediate-level waste are considered to be negligible in relative terms (IAEA, 2003).

Towards this end, the 2002 *Nuclear Fuel Waste Act* created the Nuclear Waste Management Organization (NWMO) and charged it with determining a suitable approach to managing high-level nuclear waste and carrying out its implementation (NWMO, 2005). The NWMO's favoured approach, termed Adaptive Phased Management (APM), is three-pronged: In the first phase (0-30 years), waste will continue to be stored at existing nuclear reactor sites on an interim basis and will then be prepared for either centralized storage or for long-term disposal. This will be followed (over the next 30 years) by either underground centralized storage (0-50 meters below the surface) with the option of future retrieval, or the status quo. Finally (beyond 60 years), the waste will be placed in long-term containment in a deep geological repository, likely somewhere in the Canadian Shield (500-1,000 meters below the surface) (NWMO, 2005).

Geological repositories are considered to be able to safely accommodate nuclear waste (MIT, 2003). Although it is believed that such an approach is technically viable, whether it is also politically or socially feasible remains equivocal at this time (OPA, 2005). One major omission from the NWMO's plan is a physical location for the geological repository. When an actual site is eventually chosen, it is possible that locally affected communities will object to its implementation, which could "place great stress on operating, regulatory, and political institutions" (MIT, 2003, p. 10).

Although the Adaptive Phased Management proposal has yet to be approved by the Canadian Nuclear Safety Commission, for the purpose of this assessment it is assumed that Adaptive Phased Management will ultimately be carried out. Key costs associated with this plan include labour and construction involving loading and repackaging waste, building the repository facilities and transporting and depositing the waste into the repository.

Two sources in the literature provide estimates for the marginal costs associated with nuclear waste management.[142] Figure 5-18 presents such costs and the average, \$0.00155/kWh, is incorporated into the LUEC analysis. [143]

Figure 5-18: Nuclear waste management cost

Source	Ayres et al. (2004)	OPA (2005)	Average
Waste management cost (\$/kWh)	0.00155	0.00154	0.00155

It is noted that since Ontario nuclear operators set aside a portion of funds to pay for decommissioning and waste management costs each year, such costs are classified as private costs.[144]

[142] It is unclear whether these estimates are based on the NWMO's cost projections for APM. In sum, this undertaking is expected to cost \$24.4 billion (over a period of 350 years), which amounts to a present value cost of \$6.1 billion (2004 CDN\$) at a discount rate of 5.75% (NWMO, 2005). Each nuclear operator is required to share in the waste management costs at a level that is proportional to amount of fuel bundles it generates. It is estimated that 88% of the projected high-level nuclear waste in Canada (roughly 1.75 million bundles) is produced in Ontario (NWMO, 2005).

[143] This cost does not include potential health or environmental damages since routine emissions during waste management are believed to be negligible (OPA, 2005). Potential accidents during this part of the fuel cycle may be of major consequence, but this potential external effect is considered separately in section 5.3.3.5.1.

[144] The majority of the decommissioning and waste management costs will be incurred well into the future. Consequently, Ontario Power Generation adds to a Decommissioning Fund and a Used Fuel Fund on an annual basis. As of Dec. 31, 2005, the balance of funds set aside by OPG was \$6,788 million (OPG, 2006a). Due to a leasing arrangement between OPG and Bruce Power, OPG remains responsible for the decommissioning and waste management costs that are generated at the Bruce Nuclear Station (OPA, 2005). Funds are deposited into segregated accounts and cannot be used for other purposes, in accordance with the Ontario Nuclear Funds Agreement. The funds set aside are assumed to grow to a level that is sufficient to cover the costs of decommissioning and waste management at a future date. Consequently, the potentially external costs associated with decommissioning and waste management are considered to be internalized, which is a position that is supported by ExternE (EC, 2005). However, the validity of the internalization assumption is contingent on several factors. For internalization to hold, the actual cost in the future must be equal to or less than the cost estimate. Due to the lack of previous experience with decommissioning and waste management on a commercial scale this assumption may rest on a poor foundation (Thomas, 2005). Thomas (2005, p. 24) notes that "All experience of nuclear power suggests that unproven processes could easily cost significantly more than expected. There is therefore a strong risk that forecasts of these costs could be significantly too low". Moreover critics have cited that the partiality of the NWMO could be a concern in this regard: Winfield et al. (2004, p. 121) state that "Because this organization is dominated and governed by the nuclear industry, its ability to make a credible or objective decision has been challenged." Furthermore, if the return on the funds is lower than expected, or OPG experiences insolvency before the funds have been sufficiently set aside (as was the case with British Energy in Britain), future generations may be required to fund some of the costs, in which case, some of the cost would not be internalized (Thomas, 2005). If it becomes apparent in the future that some portion of decommissioning or waste management costs are in fact external, this should be reflected in the LUEC analysis. However, due to the lack of data at this time, such costs are assumed to be internalized.

5.2.3.6 Nuclear planning assumptions

5.2.3.6.1 Generating unit capacity

The 12 reactor units eligible for refurbishment have an average capacity of 752 MW.[145] New Candu 6 units are assumed to have a 700 MW capacity (AECL, 2006a). Both figures are used in the LUEC analysis.

5.2.3.6.2 Average capacity factor

The average capacity factor over the operating life of a nuclear generating unit can have a considerable impact on its financial performance. Since nuclear fixed costs are so great, increasing a unit's electricity output allows the cost to be spread over a larger base and thus the costs per unit of electricity are lowered (Thomas, 2005). In addition, a lower than expected average capacity factor results in increased maintenance costs and may increase overall electricity costs because potentially more expensive generation sources will need to be utilized while reactors are out of service (Thomas, 2005).

The historical average capacity factor of Candu nuclear units in Ontario have fallen short of their original expectations. The average lifetime capacity factor for Ontario's active fleet of nuclear units is 76%, which is lower than the nuclear industry's claims, which tend to be upwards of 80% (IAEA, 2006b). Moreover, in the 1990s, the performance of Canada's nuclear fleet had the distinction of being the least reliable among the countries in the OECD (Gibbons, 2006). While the performance of Candu reactors abroad have fared somewhat better than their Ontario counterparts in recent years, critics note that Candus have experienced extensive technical difficulties and may continue to do so in the future due to the complexity associated with their fuel channels - a design that is a distinctive characteristic of Candu nuclear technology (Winfield et al., 2004).

Various recent capacity factor estimates noted in the literature are optimistic that such technical difficulties that have plagued Candus in the past will be overcome.[146] The

[145] This calculation encompasses the four units at Pickering B (516 MW each), four units at Darlington (881 MW each) and four units at Bruce B (769 MW each).

average capacity factors obtained from five previous evaluations are presented in Figure 5-19. In addition, the mean lifetime average capacity factor for all currently active Ontario nuclear reactors is included as well. The average from these sources, 81%, is incorporated into this assessment for both nuclear refurbishment and new generating units.

Figure 5-19: Nuclear average capacity factor

Source	CIBC (2004)	Ayres et al. (2004)	OPA (2005)	IEA & OECD NEA (2005)	OCAA (2006)	IAEA (2006b)	Average
Average capacity factor (%)	85	90	85	85	65	76	81

5.2.3.6.3 Operating life

The average operating lifetime is different for refurbishment than for new generating units. Figure 5-20 shows that 13 years is the average length of time that refurbished units are expected to last, while 29 years is estimated for new generating units before a decision must be made on whether they should be refurbished or retired. To maintain consistency in the evaluation of generation alternatives, it is assumed that refurbishments are assembled in "blocks" of two such that at the end of 13 years when the first unit comes offline a second unit with the exact same characteristics is activated for another 13 years. Thus, the operating lifetime for refurbished units is effectively 26 years.

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[146] However, Thomas (2005, pp. 24-25) warns that this optimism may be unfounded. He states, "Over the past four decades, there has consistently been a wide gap between the performance of existing nuclear plants and the performance forecast for new nuclear plants. The expectations have almost invariably proved over-optimistic. The gap in expected performance is as wide as ever between current forecasts of the economic performance of the next generation of nuclear power plants and that of the existing plants. While the fact that in the past, such expectations have proved wrong is not a guarantee that current forecasts would prove inaccurate, it does suggest that forecasts relying on major improvements in performance should be treated with some skepticism". Moreover, Greening (2005, p. 1) notes that "These features of the Candu reactor design – that is the need for hundreds of fuel channels, end fittings, feeder pipes, annulus gas supply and return lines; as well as elaborate D_20 recovery and tritium control systems – have proven to be the source of unreliability and poor performance of aging Candu reactors, especially compared to reactors of similar age incorporating less complex designs operating around the world. Unfortunately, the most significant of Candu's deficiencies are long-standing problems caused by technical (design) issues that remain largely unresolved to this day".

Figure 5-20: Nuclear operating life

Source	Torrie & Parfett (2003)	Winfield et al. (2004)	Thomas (2004)	CIBC (2004)	Ayres et al. (2004)	OPA (2005)	IEA & OECD NEA (2005)	Average
Refurbishment operating life (years)	13	13	n/a	12	n/a	n/a	n/a	13
New generating unit operating life (years)	26	25	23	n/a	30	30	40	29

5.2.3.6.4 Discount rate

Private costs are evaluated under two scenarios. First, costs are assessed using a 5% public discount rate. Then, a merchant discount rate of 13% is applied, based on the cost of equity for an all-equity project. Discount rates are expressed in real terms and are presented in Figure 5-21. It is assumed that the discount rate associated with refurbishment projects are the same as with the construction of a new nuclear generating unit, which may not be the case in practice. It is further assumed that the discount rate is unaffected by the Ontario nuclear operator that is associated with a merchant project.[147]

Figure 5-21: Nuclear discount rate

Perspective	Public	Merchant
Discount rate (%)	5	13

[147] It has been noted that Ontario Power Generation and Bruce Power have different ownership structures. Under a merchant scenario the cost of capital available to Bruce Power would reflect its status as a consortium of private concerns. Since OPG is a crown corporation, its cost of capital may be lower than Bruce Power's. However, although OPG is not technically a commercial entity, it functions like one: The stipulations of the 1998 Ontario Electricity Act state that OPG is obliged to remit tax payments to the Ontario Electricity Financial Corporation. Moreover, long-term corporate credit ratings of BBB+ by Standard and Poor's and A (low) by Dominion Bond Rating Service are below that of government agencies, which reflects increased risk (OPG, 2006a & 2006b). Consequently, it is assumed that the discount rate under the merchant scenario is applicable to both nuclear operators and there is no need for further adjustment.

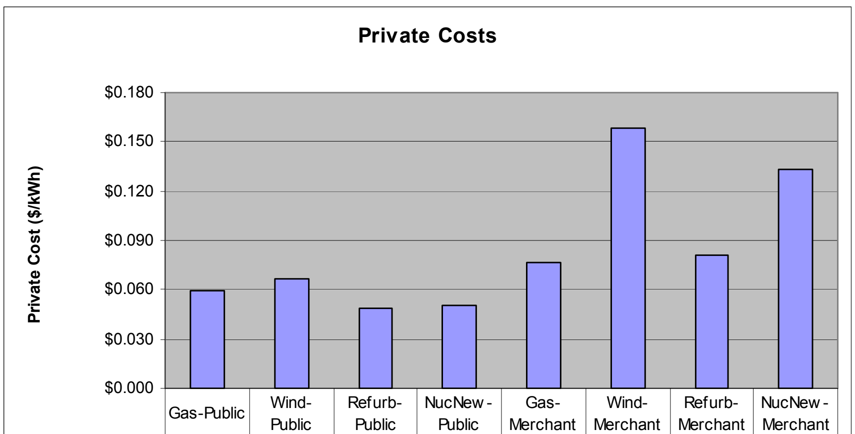
5.2.3.7 Total private costs of nuclear-fired electricity generation

Based on the private cost figures and planning assumptions selected, the private costs associated with nuclear refurbishments are $0.049/kWh from a public perspective and $0.081/kWh from a merchant perspective.[148] Private costs for new nuclear generation are $0.051/kWh from a public perspective and $0.133/kWh when a merchant perspective is applied.

5.2.4 Private cost summary

Figure 5-22 illustrates the total private cost estimates for each generation alternative.

Figure 5-22: Private cost summary ($/kWh)



	Gas-Public	Wind-Public	Refurb-Public	NucNew - Public	Gas-Merchant	Wind-Merchant	Refurb-Merchant	NucNew - Merchant
Private Cost	$0.060	$0.067	$0.049	$0.051	$0.076	$0.158	$0.081	$0.133

In the public perspective, nuclear refurbishment exhibits the lowest private costs per kWh and in the merchant perspective natural gas has the lowest private costs on a per kWh basis. A summary of the breakdown of individual private cost elements for each generation alternative is shown in Figures 5-23 and 5-24. The generation alternatives are ranked in terms of lowest private costs and the alternative with the lowest private costs in each scenario is highlighted in bold.

[148] Refer to Appendix C (i and ii) for LUEC calculations.

Figure 5-23: Summary of private cost elements for each generation alternative ($/kWh), public perspective

Public Scenario	Natural gas	Wind	Nuclear Refurbishment	New Nuclear
Private costs				
Capital	0.009	0.047	0.029	0.031
O&M	0.006	0.015	0.014	0.014
Fuel	0.045	n/a	0.003	0.003
Integration & balancing	n/a	0.005	n/a	n/a
Waste & decommissioning	n/a	n/a	0.003	0.003
Income tax	n/a	n/a	n/a	n/a
Total private costs	0.060 (3)	0.067 (4)	**0.049 (1)**	0.051 (2)

Figure 5-24: Summary of private cost elements for each generation alternative ($/kWh), merchant perspective

Merchant Scenario	Natural gas	Wind	Nuclear Refurbishment	New Nuclear
Private costs				
Capital	0.019	0.097	0.046	0.077
O&M	0.005	0.015	0.014	0.014
Fuel	0.045	n/a	0.003	0.003
Integration & balancing	n/a	0.005	n/a	n/a
Waste & decommissioning	n/a	n/a	0.003	0.003
Income tax	0.007	0.041	0.015	0.036
Total private costs	**0.076 (1)**	0.158 (4)	0.081 (2)	0.133 (3)

Natural gas is dominated by fuel costs. Alternatively, capital costs have a more significant weighting in the private cost structure of wind and new nuclear generation.

In the next part of this chapter, the computable external costs of each generation alternative are identified, quantified and monetized.

5.3 Step 3: Computable external burden assessment

Step 3 of the methodological framework in Figure 4.1 requires external costs to be estimated for each generation alternative. The assessment begins with a description of the complete fuel cycle. Subsequently, computable external burdens, which are those that have sufficient data, monetization ability and are non-negligible, are assessed based on the methodology presented in Chapter Four. Once the computable external burdens have been determined, the benefit transfer approach is used to obtain costsfrom the most relevant sources in the literature and in some cases they are adapted for the Ontario context. External burdens are quantified and monetized using either the bottom-up damage cost method or other context specific valuation techniques, which are explained where applicable. Such computable external burdens are identified and classified in terms of occurring during power conversion or non-power conversion fuel cycle stages and the key factors that influence the derivation of the estimates are described. In addition, several incomputable burdens that have been identified in the literature are also discussed here in qualitative terms, albeit with a greater emphasis on the particular incomputable external effects that exhibit poor data availability and/or monetization ability but which are thought to be potentially non-negligible.

5.3.1 Natural gas fuel cycle

The natural gas fuel cycle is comprised of the following stages: exploration; extraction; production and processing (i.e. purification); construction of long-range transportation pipeline, local storage and distribution networks and generating facilities; long distance transportation via pipeline; local storage and distribution; and power generation (OPA, 2005). In addition, the natural gas generating unit will have to be decommissioned once it ceases generating electricity. Most of the natural gas consumed in Ontario for the purpose of electricity generation is delivered to the hub in Dawn, Ontario from the Western Canada Sedimentary Basin (WCSB) and to a far lesser extent from the U.S. (OPA, 2005).

5.3.1.1 Computable external costs associated with the natural gas fuel cycle

Based on the evaluation of the 14 electricity externality data points identified in Figure 5-25, the two computable external burdens evaluated for the natural gas fuel cycle are potential climate change impacts and premature mortality associated with air pollution.[149] The Ontario-specific external costs for each burden are discussed.

Figure 5-25: Assessment of computable external burdens in the natural gas fuel cycle

Study	Monetized climate change costs, as a percentage of computable external costs (%)	Monetized premature mortality costs associated with air pollution, as a percentage of computable external costs (%)	Other external costs as a percentage of computable external costs (%)
Rowe et al., (1995)	n/a	56%	44%
ORNL & RfF (1998)	n/a	10%	90%
Maddison (1999)	67%	22%	11%
EC (1999b) Spain	66%	26%	8%
EC (1999b) Greece	54%	27%	19%
EC (1999b) Italy	53%	37%	10%
EC (1999b) Netherlands	76%	18%	7%
EC (1999b) Norway	96%	3%	1%
EC (1999b) Portugal	95%	2%	3%
EC (2004) Belgium	82%	13%	4%
EC (2004) Germany	71%	8%	22%
EC (2004) France	57%	6%	38%
EC (2004) UK	95%	6%	0%
DSS for MOE (2005)	26%	74%	0%
Average	70%	22%	20%

Sources: as indicated

Note (a): individual study percentages may not add up to 100% due to rounding.

Note (b): the sum of the averages does not add up to 100% due to the presence of n/a (not applicable) for particular external burdens. The term n/a is used to signify that the original authors decided not to evaluate a particular external burden as opposed to estimating a value of zero.

[149] Refer to Appendix C (iii) for a more comprehensive list of computable external burdens for each data source.

5.3.1.2 Power conversion stage

5.3.1.2.1 Climate change costs

According to the electricity externality studies assessed, the most significant external burden associated with electricity generation from natural gas is the cost associated with climate change.[150] Climate change refers to an increase in the average temperature of the Earth's surface, which is associated with the variability of climatic elements such as precipitation, wind and weather systems. Natural gas-fired electricity generation produces greenhouse gas emissions that have been linked by numerous researchers to climate change via the enhanced greenhouse effect (IPCC, 2001a).[151]

From 1850 to 2000, the average surface temperature of the Earth increased by roughly 0.6°C, while atmospheric concentrations of carbon dioxide increased by 32% from approximately 280 parts per million (ppm) to approximately 370 ppm (IPCC, 2001a). According to the Intergovernmental Panel on Climate Change (IPCC, 2001a), it is likely that GHG emissions, which have largely been caused by human activity (i.e. burning fossil fuels and deforestation), have contributed to this rise in temperature and are likely to continue to do so in the future.[152] The potential effects of climate change are a concern

[150] The terms climate change and global warming are used here interchangeably.

[151] Various greenhouse gases are naturally present in the atmosphere and have a positive radiative forcing on the average global temperature (IPCC, 2001a). The concentration of these naturally occurring greenhouse gases (GHGs) is influenced by a number of factors including volcanic eruptions, the natural variability of the sun's heat, and the growth and decay of vegetation. Such GHGs are responsible for the so-called greenhouse effect, which is "the redirection of thermal infrared towards the Earth" (Baird, 1999, p. 175). In the absence of this phenomenon, the average temperature on the surface of the Earth would be -18°C instead of 15°C (IPCC, 2001a). For many scientists investigating global warming, the cause for concern is that the increased concentration of GHGs in the atmosphere is leading to an enhanced greenhouse effect, whereby a greater amount of thermal infrared light will be redirected back to Earth, increasing the average surface temperature beyond the natural level (IPCC, 2001a). Each greenhouse gas is assigned a global warming potential (GWP), which is a "measure of the relative radiative effect of a given substance compared to CO_2," expressed in terms of carbon dioxide equivalent (CO_2-eq) (IPCC, 2001b, p. 46). For instance, the GWP of methane is 23 times that of carbon dioxide over a period of 100 years. Although water vapour is the most prevalent GHG and is responsible for two-thirds of the GHG effect (Baird, 1999), carbon dioxide and other GHGs including methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFCs) and chlorofluorcarbons (CFCs) are the GHGs that are focused on by researchers and policy makers, as they can be reduced by altering human behaviour.

[152] Although the surface temperature of the Earth has increased since the onset of the industrial revolution and this has corresponded with a rise in GHG emissions, it has yet to be proven conclusively whether a

at the global level since greenhouse gas emissions contribute to global warming regardless of where they are produced (i.e. greenhouse gas emissions contribute to the same effect whether they are produced in Ontario or abroad). Moreover, the problem is long-term since greenhouse gases can remain in the atmosphere for centuries.

IPCC (2001a) warns that the Earth's average surface temperature could rise between 1.4^{o}C and 5.8^{o}C by 2100. This may cause a number of biophysical impacts to develop including rising sea levels, movement of warmer climatic zones towards the poles and increases in extreme weather events such as hurricanes, heat waves, droughts and forest fires.

Such biophysical impacts may result in significant damages to human welfare and ecosystems. However, determining precise impacts on a global, regional or local scale is difficult due to the complexity of climate systems and the resiliency and adaptive capacity of ecosystems and human populations (IPCC, 2001a). Moreover, cumulative effects of GHG emissions may be non-linear and may exhibit tipping points, "where change can be large, rapid and possibly irreversible" (Government of Canada, 2005, p. 34). Moreover, "[s]cientific knowledge is at a preliminary stage when it comes to what changes in levels of GHG concentrations might cause these 'tipping points' to occur" (Government of Canada, 2005, p. 34).

However, it believed that significant human mortality and morbidity effects may occur due to flooding, disruption of food production and fresh water supplies and proliferation of insect-borne disease. It is believed that such effects will not be uniformly distributed throughout society as a result of shifting climatic zones, geography, weather patterns, demographic and socio-economic factors and the adaptive capacity of ecosystems and

causal link exists between the two phenomena. Scientists cannot confirm that the rise in temperature is attributable to increased GHG emissions or another unknown factor, or if it is simply a natural variation of the Earth's climate. However, in the absence of conclusive evidence, the prevailing wisdom of the majority of researchers and scientific institutions is that climate change is occurring; it is human-induced; and it may produce a number of unfavourable and potentially catastrophic impacts if adequate preventative action or adaptive measures are not taken (IPCC, 2001a). The IPCC states that "There is new and stronger evidence that most of the warming observed over the last 50 years is attributable to human activities" (IPCC, 2001a, p. 5).

people. Poor people, particularly those located in coastal regions, appear to be most vulnerable. Similarly, ecosystems that are particularly vulnerable and endangered species are likely to be the most severely affected because they have a more limited adaptive capacity (ORNL & RfF, 1998). Ironically, some effects in certain regions will be favourable, such as in the case of reduced heating costs. However, the net effects are expected to be unfavourable and are expected to intensify the more the temperature rises (IPCC, 2001a).

Like all other nations, Canada could be significantly affected by climate change, with northern regions being particularly vulnerable (Government of Canada, 2005). Arctic temperatures are expected to rise faster than the global average and could potentially reach 12^{o}C higher than pre-industrial times. It is likely that if current trends persist there will be significant impacts to northern ecosystems, human health and the standard of living of inhabitants of northern regions. Indigenous peoples may find it hard to preserve their traditional culture and livelihood as they are forced to adapt to climate change (Government of Canada, 2005). In addition to such effects, Canada's sovereignty in the North may be challenged as shipping routes open up as ice floes thaw. Buttle et al. (2004) also warn that hydro-powered electricity generation utilizing the Great Lakes may be negatively affected as well due to increased evaporation (which is believed to more than offset the effects of increased precipitation).

Efforts to mitigate climate change impacts involve reducing GHG emissions and utilizing more sustainable agricultural and forestry practices. Policy makers must proceed appropriately given the high level of uncertainty that exists, taking into consideration the fact that the timing of GHG reductions could be as important as the reductions themselves. Strategies intended to prevent potentially unfavourable impacts must be adequate to allow adaptation measures to succeed and must balance the risks associated with excessive and insufficient action. At the international level, the regulatory mechanism for reducing GHG emissions is the Kyoto Protocol to the United Nations Framework Convention on Climate Change. The Kyoto Protocol became a legally binding agreement upon the nations that ratified it on February 16, 2005. It was originally opened for signature in Kyoto, Japan on December 11, 1997, committing industrialized countries to reduce greenhouse gas emissions by 5.2% below 1990 levels by the commitment period between 2008 and 2012 (UNFCCC, 1997). However, it is believed that if climate change is to be averted, deeper reductions beyond the Kyoto Protocol target will be required in the future (IEA, 2002a).[153] Yet, an international strategy past 2012 has yet to be agreed.[154]

Under the stipulations of the Kyoto Protocol, each country participating in the agreement must meet the country-specific target that is laid out. Canada is required to reduce greenhouse gas emissions to 6% less than 1990 levels on average, from 2008 to 2012. Since GHG emissions in Canada have increased significantly since 1990, this reduction is now equal to 270 megatonnes (MT) of CO_2-eq, making Canada's GHG reduction target the most challenging of any Kyoto signatory in absolute terms (Government of Canada, 2005).[155]

Due to the significant level of uncertainty with respect to climate change effects as well as the ability to mitigate and adapt to them, determining the costs associated with climate change remains an extremely difficult task. Assessing the marginal costs of such impacts

[153] According to IEA (2002a, p. 31), this entails aiming "for the lowest possible emission or concentration levels that are feasible – recognising that their achievement would be constrained by cost…It already appears to be impossible to return to pre-industrial CO_2 concentrations (275 ppm) – or even to stabilise atmospheric CO_2 concentration at 350 or 400 ppm….without near-term action, the option of stabilising emissions at 450 ppm would disappear from the range of possible alternative end-points within a few decades". In the literature, a proposed goal of stabilizing the atmospheric concentration of GHG at 550 ppm is often thought to be acceptable (IEA, 2002a). Consequently, global emissions would need to be reduced by 50-60% below 1990 levels by 2050 in order to stabilize atmospheric concentrations of greenhouse gas emissions at twice pre-industrial levels (550 ppm) (Government of Canada, 2005). Worryingly, even if GHG emissions are stabilized, there will probably be a lag with respect to the stabilization of GHG concentrations. Consequently, the average surface temperature may continue to rise and significant impacts (e.g. glaciers melting, oceans experiencing thermal expansion and sea levels rising) may well occur even after GHG emissions have been curbed (IEA, 2002a and IPCC, 2001a)

[154] Many participants have viewed the Kyoto Protocol as a first step towards deeper GHG reductions that would take place in the future. Parties to the United Nations Framework Convention on Climate Change are engaged in consultations that will determine what multi-lateral GHG reduction strategies, if any, will be pursued in the post-Kyoto period.

[155] In 1990, Canada's annual GHG emissions were 596 MT CO_2-eq. By 2003, this figure had increased by 24% to a total of 739 MT CO_2-eq, in part due to the surging economy, which grew by 43% during this time. It is projected that by 2010, under a business as usual scenario, Canada's annual emissions will reach 830 MT CO_2-eq (Government of Canada, 2005). Therefore, GHG emissions must be reduced by 270 MT CO_2-eq by 2008-2012 to reach the target of 560 MT CO_2-eq.

is even more challenging. Uncertainty goes well beyond the science itself and the specific impacts that may occur. There are also significant unknowns regarding population levels; the resiliency of ecosystems and the adaptive capacity of human institutions and communities; the effectiveness of GHG mitigation strategies; and technological advances that may materialize in the future that could help alleviate damages (IEA, 2002a). The IEA (2002b, p. 36) states that "[c]limate change is an extraordinarily complex, multi-sectoral problem involving multiple social, economic, political, environmental and ecological factors over a very long time-frame."

Despite the significant level of uncertainty, failing to account for climate change impacts in electricity externality studies is currently untenable. This was not the case up until the late 1990s. For instance, Rowe et al., (1995) and EC (1995) did not include external cost estimates for climate change, while more recent studies such as Venema and Barg (2003) and DSS for MOE (2005) incorporate this burden into their assessment.

Over the past 15 years, a significant number of monetized estimates for climate change impacts have been developed in the literature (refer to Tol (2005) for an extensive listing). According to Owen (2006, p. 637), "[t]his is a very contentious area, and the range of estimates for the possible economic ramifications of global climate change is vast". Climate change cost estimates have varied for the same reason that electricity externality study estimates have varied: different methodologies and assumptions have been used to derive the estimates (IPCC, 1995; 2001a).

The majority of previous climate change valuation studies have evaluated the costs and benefits of GHG reduction using the top-down or bottom-up method (IPCC, 1995). Top-down models look at the macroeconomic effects of key variables that could be affected by climate change. The main kinds of top-down models are macroeconomic and equilibrium models (Fankhauser, 1995). Macroeconomic models express the effects of carbon abatement on macro indicators like employment and inflation (e.g. Hall et al., 1994 cited in Fankhauser, 1995). Equilibrium models describe the impact of price changes on the economy. Long-run equilibrium models are either general or partial (i.e.

restricted to one sector; also known as resource allocation models) (Fankhouser, 1995). On the other hand, "[b]ottom up models are technology oriented, engineering based studies, which concentrate on the availability and performance of individual energy supply technologies" (Fankhauser, 1995, p. 96).

Studies also differ as a result of numerous assumptions such as whether they include GHGs besides carbon dioxide; internalization mechanisms like emissions trading or taxation; ancillary costs and benefits, transaction costs; capacity for technological advancement; and in terms of their degree of comprehensiveness with respect to macroeconomic effects (IPCC, 2001a). Other important assumptions are the so-called "ethical parameters", namely how premature mortality in developing countries is treated and the discount rate used, which have significant implications for intergenerational and intra-generational equity (Tol, 2005).[156]

Tol (2005) performed a meta-analysis of the results of 28 published studies that evaluated the damage costs associated with climate change and the results reveal a median damage cost estimate value of $14/tonne CO2-eq and a mean of $93/tonne CO2-eq. However, these values decrease significantly when only the results of peer-reviewed studies are considered. In general, Tol concludes that marginal damage costs of CO2-eq are "unlikely to exceed" $50/tonne CO-eq (all figures in 2004 USD). Tol also states that, "economic valuation can be controversial, and requires sophisticated analysis that is still mostly lacking in a climate change context" (Tol, 2005, p. 2065).

Hence, as a result of the significant amount of uncertainty with respect to climate change damage cost estimates, utilizing the expected GHG permit price has emerged as a "second-best" option, following the rationale of the abatement cost approach (EC, 2005). According to ExternE (EC, 2005, p. 21), "abatement costs can be a valuable source of

[156] The concept of the value of a statistical life, which is the cost associated with an increase in the risk of death, is often used to evaluate premature mortality (EC, 2005). This external burden will be discussed in greater detail in section 5.3.1.2.2, which covers premature mortality associated with non-greenhouse gas air pollutants. The key point with respect to climate change impact valuation is that several climate change estimates in the literature, which have been conducted mainly by researchers in developed nations, have used a lower value for the value of a statistical life for people in developing countries relative to people in developed countries.

information for impacts whose monetary valuation has not yet been satisfactory or even possible, in particular global warming." With the launch of tradable GHG emission permit systems designed to meet Kyoto Protocol requirements, the expected GHG emissions permit price has been used as a proxy for the cost of the burdens associated with climate change.[157] For instance, the European Emissions Trading System (EU ETS) has been active since 2005, with trading in the €6 to €30 per tonne of CO_2-eq range (Point Carbon, 2006). Various studies have forecasted that the cost of Certified Emission Reductions for the Clean Development Mechanism associated with the Kyoto Protocol will be in the range of $5 to $15 per metric tonne (EIA, 2005), whereas ExternE (EC, 2005) considers €5 to €20 per tonne of CO_2-eq an acceptable range. However, it must be acknowledged that the GHG permit price reflects the marginal cost of meeting the regulated emission amount and not necessarily the potential damages incurred. Consequently, the GHG permit price may well only be a subset of the total marginal costs associated with climate change impacts.[158]

Although an emissions trading system is not currently active in Canada, recent developments allow for educated conjecture with respect to a future GHG reduction permit price that may be used as a proxy for the marginal costs associated with GHG emissions in the Ontario context. Under the stipulations of the Kyoto Protocol, Canada is required to reduce GHGs 6% by 2008 - 2012. Towards this end, the previous Canadian government released a plan for meeting the target, entitled "Project Green Moving Forward on Climate Change: A Plan for Honouring our Kyoto Commitment", which includes reduction targets for Large Final Emitters (LFEs) like natural gas-fired

[157] Such a cap-and-trade system refers to a tradable emissions market in which a market-wide limit is set by a regulatory body, market participants are issued permits worth a specified proportion of the market wide limit, and trade among participants is carried out depending on their ability to comply with individual permit targets.

[158] GHG permit prices are a function of Kyoto Protocol targets and these reflect political maneuvering and negotiation in addition to scientific data and may not adequately account for the complete set of damages incurred as a result of climate change. Spalding-Fecher and Matibe (2003) note that the initial distribution of emission permits may be politically challenging. For example, in May, 2006, the price of CO2-eq on the EU ETS declined significantly after reports that several countries were well on track to meet their GHG reduction targets, which - it has been speculated - is a result of lenient allocation levels (Point Carbon, 2006). Moreover, it is believed that significantly deeper reductions beyond Kyoto Protocol levels are required to sufficiently mitigate climate change effects to a level that people will be able to adapt (IEA, 2002a). A more detailed discussion as to why abatement costs should only be considered an approximation of damage costs is found in section 3.3.1.

electricity generators (Government of Canada, 2005).[159] "Project Green" indicated that GHG reductions would be facilitated by employing a market-based GHG permit trading system, although it also noted that regardless of the actual market price of the permit, LFEs' cost of compliance would be capped at a maximum of $15 per tonne of carbon dioxide equivalent during the commitment period between 2008 and 2012 (i.e. the cost to LFEs could be lower than $15 depending on market fluctuations, but in the event that the permit price rises above $15, the Government intends to cover the difference) (Government of Canada, 2005).[160] Details of the trading system, including emission allocations among sectors and firms, have yet to be unveiled.[161] Moreover, it is unclear whether the cap would remain in place beyond 2012. In the absence of this price ceiling, permit prices would become a function of post-Kyoto GHG reduction targets and abatement or technology costs.

Despite recent political developments, a $15/tonne of CO_2-eq permit price ceiling in an operational GHG permit trading market remains a legitimate possibility. In the light of the preceding discussion, a marginal cost of $15/tonne of CO_2-eq for climate change external costs is considered appropriate for this assessment.[162]

Natural gas-fired electricity generation produces 0.0003526 tonnes of CO_2-eq/kWh (DSS for MOE, 2005).[163] Therefore, the external costs of climate change effects associated with natural gas-fired electricity generation in Ontario are $0.005/kWh.[164]

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[159] LFEs consist of approximately 700 large Canadian companies in the mining, manufacturing, oil & gas and thermal electricity sectors that emit 8 kilotonnes or more. These emitters are jointly responsible for producing approximately 50% of total GHG emissions in Canada. However, the proposed system would require them to collectively reduce GHG emissions by 45 MT (Government of Canada, 2005).

[160] Individual sectors and emitters within each sector will have different costs to achieve their allocated permit for a fixed level of emissions. In the proposed trading system, emitters that over-comply will be rewarded by being able to sell permits to emitters that cannot comply with their permit level.

[161] This situation is further complicated by a change in Canada's governing party, which has not stated its intention on this matter.

[162] It is assumed that $15/tonne of CO_2-eq cost is expressed in real terms even though this was not explicitly stated by the government. If the cost figure was expressed in nominal terms, this would imply that the real costs of meeting climate change obligations are expected to decrease every year, which does not appear to be the view held by researchers and policy makers.

[163] This is generally consistent with GHG emissions data found in other reports. For example, Diener (2001) (0.000367 tonnes CO_2-eq/kWh); Dones et al. (2005) (0.000423 tonnes CO_2-eq/kWh); and OPA (2005) (0.00029 tonnes CO_2-eq/kWh).

5.3.1.2.2 *Premature mortality costs associated with air pollutants caused by natural gas-fired electricity generation*

Human premature mortality impacts are attributed to air pollution caused by natural gas-fired electricity generation. The cost derived by DSS for MOE (2005) for this external burden is adopted here (along with some minor adjustments) since DSS for MOE (2005) employs a bottom-up methodology and was conducted from a similar perspective as this assessment.[165] This section describes the emissions, dispersion, impacts and monetary valuation for this external effect and puts the key factors within these stages into context in terms of how they compare with other studies in the literature. Various limitations associated with the particular findings of DSS for MOE (2005) are also presented.

<u>Source</u>

The main emissions produced by natural gas-fired electricity generation that attributed to causing premature mortality (as well as other adverse health complications) are nitrogen oxide (NO_x), which is a precursor of ground level ozone (O_3), and particulate matter (PM). However, trace elements of other pollutants are also emitted. For instance, some sulphur dioxide (SO_x) emissions are present but are thought to be negligible (DSS for MOE, 2005). In addition, carbon monoxide (CO) may also be emitted, but the effects of such emissions are currently not well enough understood to incorporate into the evaluation, rendering the impact of such emissions incomputable. This omission may understate the results (DSS for MOE, 2005).

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[164] Calculation: \$15/tonne of CO_2-eq x 0.0003526 tonnes CO_2-eq/kWh = \$0.005289/kWh. GHG emissions are based on a natural gas-fired power plant with a 90% capacity factor (DSS for MOE, 2005).

[165] It is noted, however, that the emissions profile and impacts described in this section correspond with the scenario presented by DSS for MOE (2005) in which increased natural gas-fired electricity generation is considered as a replacement for 6,447 MW of coal-fired generation in Ontario. In such a scenario, natural gas generating units are assumed to have a capacity of 425 MW, a heat rate of 7,000 Btu/kWh, an average capacity factor of 90%, and an expected operating life of 20 years (DSS for MOE, 2005). It is acknowledged that these assumptions are slightly different than the planning assumptions incorporated into this analysis. As discussed in section 4.2.3.2, this is a limitation of the methodology used here. However, since DSS for MOE (2005) assumptions are somewhat comparable to the assumptions adopted here, it is assumed that the difference will not change the outcome of the results significantly.

Nitrogen oxides are made up of nitric oxide (NO), nitrogen dioxide (NO_2) and nitric acid (HNO_3). These pollutants can lower resistance to infection in the lungs, increasing the probability of respiratory illness, especially among those with pre-existing respiratory ailments like asthma and bronchitis, and cause headaches. They react with volatile organic compounds (VOCs) and sunlight to produce ground level ozone, which is a key contributor to smog and is especially prevalent in Ontario during the summer (DSS for MOE, 2005).[166]

$PM_{2.5}$ is also emitted during natural gas-fired electricity generation. In addition, it is created by the chemical interaction among sulphur dioxide, nitrogen oxide and volatile organic compounds. The health impacts of microscopic particles vary in inverse proportion to diameter of the particulates. Respirable particles with a diameter of 2.5 microns or less ($PM_{2.5}$) are considered to be fine particulate matter and have the ability to enter the respiratory system causing health damages (DSS for MOE, 2005).[167]

Dispersion

Following studies like ExternE (EC, 1995) and Rowe et al. (1995) that developed dispersion models (Ecosense and Exmod, respectively), to track the diffusion of pollutants in an affected region, DSS for MOE (2005) utilizes a similar computer dispersion model with Ontario-specific data. This model incorporates local meteorological data, tracks chemical interactions between pollutants, accounts for local geography and pollutant transport via wind patterns and regional weather characteristics, and includes reference data on background atmospheric concentrations (e.g from natural sources, electricity generation, vehicle emissions and transboundary pollution). DSS for MOE (2005) uses the integrated CALMET/CALPUFF model, which analyzes the chemical reactions and dispersion of air pollution impacts in 44 census divisions in

[166] According to the assumptions of DSS for MOE (2005), NO_x emissions are 2.3 KT per year.
[167] According to the assumptions of DSS for MOE (2005), $PM_{2.5}$ emissions are 0.89 KT per year.

Ontario (excluding the five northernmost census divisions, which were deemed to have a negligible impact on the results).[168]

The dispersion model uses meteorological data from 1999 developed by Scire et al. (2000 cited in DSS for MOE, 2005). According to DSS for MOE (2005), "the data for 1999 provided a good cross-section of typical large-scale weather patterns throughout the study area" (DSS for MOE, 2005, p. 15). Consequently, it is assumed that Ontario weather conditions in 1999 are representative of mean weather patterns.[169] The DSS for MOE (2005) model incorporates simplified chemical reactions involving the interaction among NO_x, SO_2 and VOCs in the formation of $PM_{2.5}$ as well as NO_x, VOCs and sunlight in the development of O_3. Such modeling relationships are constrained by the same limitations as other dispersion models, which are unable to completely represent the complexities of the real world.

Dose-response function

To account for site and receptor specificity, incremental emissions are evaluated at the census division level throughout Ontario. For instance, ozone and particulate matter emission levels in Haldimand Norfolk Regional Municipality, where the Nantikoke coal-fired generating station would be modified to use natural gas, are projected to be 0.07 ppb and 0.03 mg/m^3, respectively, whereas such emissions are forecasted to be only 0.01 ppb and 0.00 mg/m^3 in the Ottawa-Carleton Regional Municipality, which is not located in close proximity to a natural gas generating unit (or another thermal-based emitter) (DSS for MOE, 2005).

The impact of emissions on each receptor is estimated by applying a dose-response function, which links the dispersed emissions to the increase in premature mortality risk for each census division. Dose-response functions are derived from epidemiological studies that measure the impact of air pollution on human health. Such epidemiological

[168] CALMET models meteorological data and CALPUFF models the dispersion of the emissions. For a more detailed description of CALMET and CALPUFF models, the interested reader is referred to Appendix A located in DSS for MOE (2005).
[169] To the extent that this is not the case, the marginal external costs associated with emissions may be slightly skewed, which is acknowledged as a limitation of this assessment.

studies may be classified as either time-series or cohort. This refers to the tracking of health impacts of an affected segment of the population. Time-series data identify acute impacts of air pollution, which are perceptible within "a few days" after exposure to pollution (EC, 2005, p.3) (e.g. number of asthma attacks in Toronto on a smog day that result in premature fatality), whereas cohort data tracks a group of people over several years to determine chronic mortality linked to long-term exposure of air pollutants (EC, 2005). Predictably, the impacts observed from cohort studies are more severe because of the inclusion of long-term effects (which inherently include some acute impacts as well). In DSS for MOE (2005), which utilizes a cohort study but presents both types of results for comparison purposes, the damages assessed by the cohort study are seven times larger than those assessed using time-series data.

Time-series studies are easier to implement because it may be hard to distinguish between acute and long-term impacts as well as control for other causes of death as with cohort studies. Time-series are also relatively inexpensive to carry out (EC, 2005). Cohort-based data, on the other hand, include health impacts associated with chronic exposure to air pollution, so it is necessary to track the health conditions of a group of individuals over time. According to Pearce, "[o]ne of the problems with acute [i.e. time-series] studies is that they may tell us numbers of people dying from acute effects but not the period of life that is foreshortened" (Pearce, 2001, p. 28). Cohort studies are able to provide information on loss of life expectancy averaged over the population as opposed to only the number of deaths linked to air pollution exposure (EC, 2005). However, to date, very few cohort studies have been reported in the literature. Among Dockery et al. (1993), Pope et al. (1995) and Abbey et al. (1999) and Pope et al. (2002), Pope et al. (2002) is noted as the most significant cohort study completed thus far (EC, 2005). Each of these cohort studies are at least seven years long, with Pope et al. (2002) having the longest duration (16 years).

Kunzli et al. (2001) recognize that time-series and cohort studies are of value in air pollution epidemiology, but the more comprehensive cohort studies are preferable. DSS for MOE (2005) advises that cohort figures are more suitable "since they capture more completely the negative effects of air pollution exposure" (DSS for MOE, 2005, p. iv). This position is supported by EC (2005) and the US EPA, which states that cohort studies "have been sufficiently validated to be used for policy analysis" (US EPA, 2003a, cited in DSS for MOE, 2005, p.19).

Epidemiological study used to quantify the impacts of air pollution attributed to natural gas-fired generation

DSS for MOE (2005) utilizes the findings of the cohort study, Pope et al. (2002), to derive the dose-response function (Ed Hanna, personal communication, 2006).[170] Pope et al. (2002) use data collected by the American Cancer Society on approximately 1.2 million adults in America from 1982 to 1998. The authors then assess the subset of respondents (approximately 500,000 adults) that live in US cities where pollution data are available. After controlling for cigarette smoking, obesity, alcohol consumption and other regional factors, the researchers find that there is a link between increased exposure to particulate matter and ozone and cardiopulmonary mortality and lung cancer mortality (Pope et al., 2002).

DSS for MOE (2005) computes the impact of dispersed emissions from natural gas-fired electricity generation in each census division by integrating emissions data with a dose-response function based on Pope et al. (2002) and baseline mortality data from CIHI (2002). Impacts are calculated by multiplying the number of potentially affected people in each census division by the change in premature mortality risk above the baseline. The increased risk of premature mortality due to the marginal natural gas-fired emissions is expressed in terms of number of fatalities.[171] According to DSS for MOE (2005), this is

[170] It is noted that the use of Pope et al. (2002) is not actually stated explicitly in DSS for MOE (2005).
[171] Results for premature mortalities associated with natural gas-fired electricity generation are expressed independently of the premature mortality estimate associated with coal-fired electricity generation, which was also calculated in DSS for MOE (2005) (i.e. the 11 fatalities associated with natural gas are independent of the number of fatalities that were associated with coal). An evaluation of the net avoidance of premature mortality by switching from coal to gas is not within the scope of this analysis.

estimated to be an average of 11 premature mortalities per year over the operating lifetime of the generating unit.[172]

DSS for MOE (2005) results are considered appropriate for this study. Pope et al. (2002), which was conducted in the United States, appears to be transferable to the Ontario context for which there are no original cohort data available. In adopting Pope et al. (1995), the predecessor to Pope et al. (2002), Chestnut et al. (1999, chapter 2, p. 4) explain that, "[i]n general, health effects and economic valuation studies in Canada show results that are reasonably consistent with results from U.S. studies".

However, some potential limitations need to be acknowledged. Impact estimates assume that people stay in their census division, which is obviously not the case as people travel outside of their locality. As a result, they may not be exposed to the exact level of air pollution estimated for their region. However, this does not seem to be a major limitation. It is also recognized that Pope et al. (2002) does not include premature mortality figures for people aged 19 and under, which could be potentially significant because some argue that very young people may be particularly susceptible to air pollution exposure (EC, 1999a). This omission likely understates the results, but the extent to which the results are affected is unknown. Furthermore, air pollution impacts on receptors that reside outside of the province (i.e. people in bordering provinces and U.S. states) are not accounted for due to a lack of data, which also understates the results. However, since the intensity of pollution effects recede the further away a receptor is from the source, this is not assumed to be a major omission.

Monetary valuation

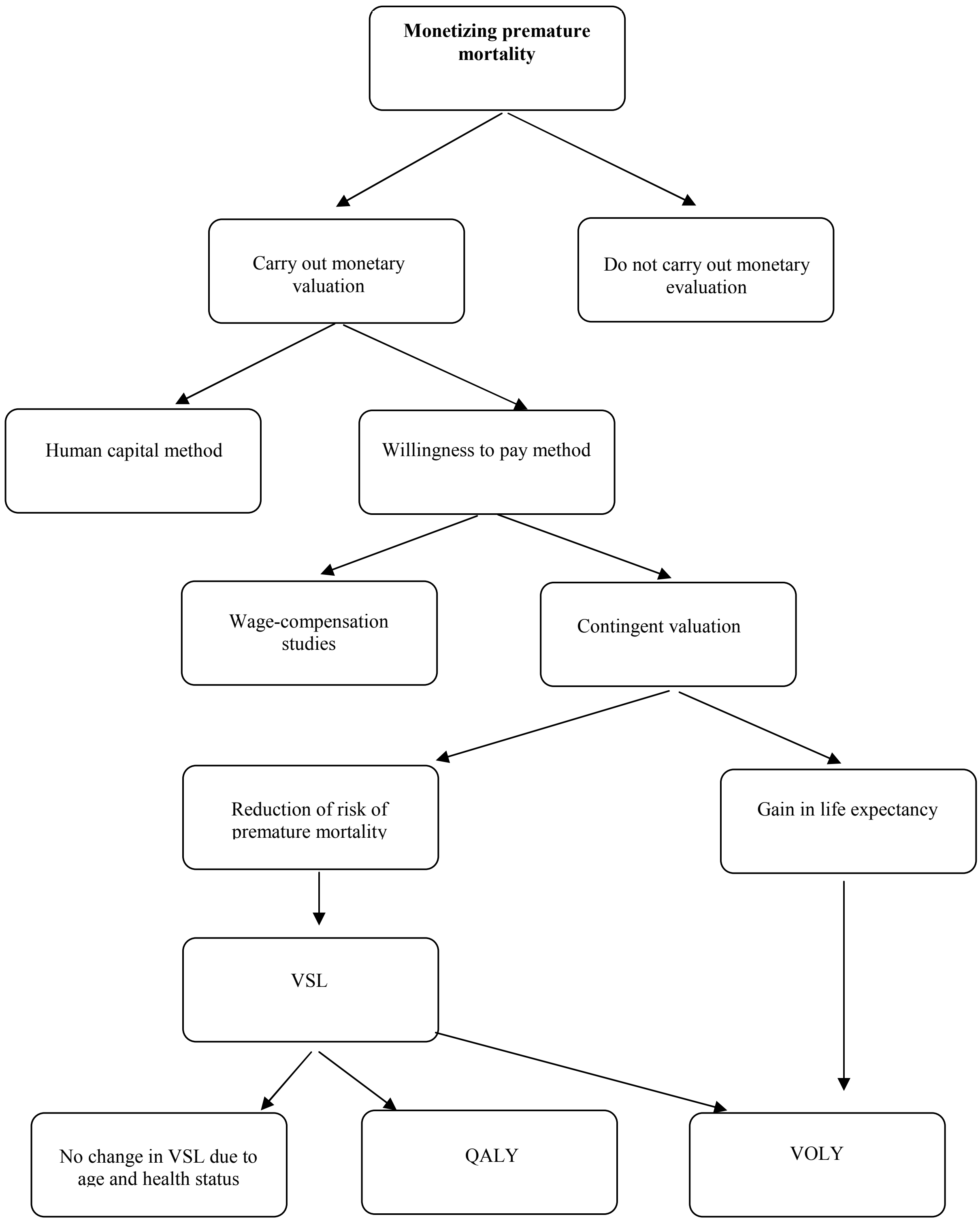
The exercise of monetizing the risk of premature death associated with air pollution is multi-faceted and can proceed along a number of different paths (refer to Figure 5-26 for a breakdown of the parameters affecting the valuation of premature mortality). As discussed in section 2.3.6, ethical concerns surround such a task. Researchers may also

[172] It is noted that only the aggregated impact results (i.e. 11 premature mortalities per year) are presented in DSS for MOE (2005) for Ontario as a whole. While emissions data for each individual census division are provided, the corresponding impact data were not made available to the public.

disagree about how to measure the preferences of society and whether or not the value obtained should be diminished by age and/or deteriorating health status to reflect the fact that elderly and infirm individuals are disproportionately susceptible to premature mortality from increased pollution exposure.

These debates are highly relevant since the selection of a particular technique can significantly influence overall external cost estimates in electricity externality studies (Krupnick et al., 2002). Perman et al. (2003, p. 168), note that "valuation of human life is by no means straightforward, [so] estimates produced by valuation studies can often be highly contentious".

Figure 5-26: Parameters affecting the valuation of premature mortality



Two general methods have been used to estimate the value of premature mortality: the human capital method and the willingness to pay (WTP) method.

<u>Human capital method</u>

The human capital method determines the value of premature mortality by aggregating the portion of a person's lifetime earnings that are negated due to premature mortality. While it is simple to calculate, it does not accurately reflect average individual risk preferences and is unconnected to reality in the sense that the value of premature mortality for someone who expects zero future earnings (such as a retired person) is zero. This method is no longer used to evaluate premature mortality associated with electricity generation (EC, 2005).

<u>Willingness to pay (WTP) method</u>

For the monetary valuation of premature mortality associated with air pollution, the human capital method has been replaced by the willingness to pay (WTP) method in much of the literature (EC, 2005). This approach is more representative of economic theory because it reflects individuals' preferences by how they choose to accept the tradeoff between risk and monetary reward, while explicitly taking non-market values into consideration. The two main techniques used to ascertain WTP are wage-compensation studies and contingent valuation.[173]

<u>Wage-compensation approach</u>

The wage-compensation approach is an example of the hedonic method, which is a revealed preference technique used to infer external costs through observed behaviour.[174] Wage-compensation studies investigate the difference in wage premiums that workers receive for the increased exposure to fatality risk inherent in their position. This approach is based on the assumption that the riskier the job is, the more one receives in compensation to carry it out.

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[173] In addition, the avertive behaviour method, a market-based method in which individuals spend money on items that reduce their risk of premature mortality also exists. However, it has been used less extensively in the literature because it is thought to be less effective than the aforementioned methods (EC, 2005).

[174] Also referred to as wage-risk in the literature (e.g. EC, 1999a)

The major benefits of such an approach are that it is easy to implement and it expresses individual preferences based on the risk-reward tradeoff. However, it is conceivable that workers may not fully understand the risk tradeoff associated with their position. Furthermore, this approach does not consider the risk preferences of people who are unemployed (ExternE, 2004). Wage-compensation is still used in premature valuation studies, but it is thought to be inappropriate for valuing premature mortality associated with air pollution because it measures accidental deaths on the job, which is not at all relevant for the air pollution context. This is because the reduction of life expectancy of accidental deaths is assumed to be approximately 30 to 40 years, whereas the reduction in life expectancy associated with air pollution is assumed to be much shorter, plus the risk levels are different as well. As a result, they are no longer relied upon to value premature mortality for electricity externality studies.

<u>Contingent valuation method (CVM)</u>

Contingent valuation, a stated preference technique, may alternatively be used to determine WTP. This method attempts to quantify individuals' collective willingness to pay (WTP) to reduce pollutants linked to premature mortality or their willingness to accept (WTA) payment for an increase in pollution by asking them directly. The benefit of this method is that preferences do not have to be inferred from different kinds of behaviour. But, since the scenario presented is hypothetical and individuals do not in reality have to forego any money, their actual behaviour may not entirely correspond with the response they give.

In the case of valuing premature mortality caused by air pollution, individuals are asked to determine their preference (expressed in monetary units) towards an incremental increase in the risk of premature mortality as a result of a marginal increase in emissions. DSS for MOE (2005, p. v) clarifies that:

> In actual fact, it is impossible to identify which specific deaths that occur over a given period of time are actually attributable to air pollution. Air pollution is a contributory factor in a multitude of deaths and is almost never the overriding or irrefutable single cause of death. This is no way implies that air pollution is not

> causing premature mortality among a great number of individuals. Instead, reporting the change in risk as the number of expected individual deaths is an easy way to communicate the damage.

Moreover, Maddison (1999, p. 9) notes:

> If people's preferences are a valid basis upon which to make judgements concerning changes in human 'well-being', then it follows that changes in human mortality and morbidity should be valued according to what individuals are willing to pay (or willing to accept as compensation to forego a given change in health status). This is not the same as valuing an actual life, and should not be interpreted as such. Instead it involves valuing ex-ante changes in the level of risk people face and then aggregating them.

Although this method is in accordance with economic theory since it measures individuals' opportunity costs in monetary units, it is subject to various limitations. In certain instances, respondents may not be fully able to understand what is being asked of them (OTA, 1994). Yet, another weakness is that intensity of preference is not revealed since the fraction of overall income an individual is willing to spend is not accounted for and instead only an absolute amount is obtained. This has implications for respondents that have very different levels of income and wealth (i.e. people with higher income and/or wealth may place a higher value on something than someone with lower income and/or wealth, *ceteris paribus*). Conversely, people may not consider their actual budget since the situation is hypothetical (ExternE, 2004).[175]

<u>Risk reduction vs. gain in life expectancy</u>

Contingent valuation surveys used by electricity externality studies may ask individuals for their WTP to reduce the risk of premature mortality or their WTP for a gain in life expectancy (LE). Obviously, reducing the risk of premature mortality and life expectancy are connected, since reduced mortality risk will increase life expectancy. However, it has been demonstrated by Rabl (2003) that people respond differently to these questions and they also produce different indicators. In fact, the mortality valuation figure given by respondents tends to be slightly higher when the questionnaire uses the reduction of risk approach. According to Rabl (2003), life expectancy is a more appropriate impact indicator than the risk reduction approach. When the question is framed in terms of

[175] For a complete list of drawbacks that could affect individuals' contingent valuation response, refer to EC (2004, p. III-11 and III-12).

reduction of risk it produces a result expressed in number of deaths. Since the primary cause of death is accelerated by air pollution over time, it is argued that loss of life expectancy is more appropriate. Consequently, the life expectancy approach has been adopted by ExternE since 1999. In contrast, Alberini et al. (2004) note that there is inconclusive evidence regarding the suitability of using life expectancy gains as a substitute for risk reduction, and believe that more research is needed in this area before a clear option is deemed preferable. ExternE (EC 2005a, p. 85), while maintaining support for the LE approach, asserts that neither approach is "universally accepted".

Value of a statistical life (VSL)[176]

If utilizing the contingent valuation method, the value of a statistical life that is obtained is an expression of individuals' collective preference towards a marginal change in premature mortality risk. It is described by the following equation (Krupnick et al., 2002):

VSL = WTP for risk reduction / change in risk reduction of premature mortality

VSL has been incorrectly interpreted by some as the actual estimated value of human life. ORNL and RfF (1992, p. 5-8) summarize why this view is erroneous:

> It is unfortunate that VSL nomenclature implies that a life is being valued: many people, including economists, are uncomfortable with such a prospect. An incorrect response to such concerns, but one frequently heard, is that a statistical life rather than a real life is being valued, the distinction being that of whether one knows in advance who will die prematurely. The appropriate response is that reducing one's risk of death is being valued, with the VSL measure being a convenient form in which to express both WTP and the size of the risk change in one measure. Evidence that people are willing to pay to reduce their risk of death can be seen in many everyday activities. Reducing the speed of one's car in rainy conditions shows a trade-off between saving travel time and reducing mortality (plus morbidity) risks. Translation of time into dollars makes the money-risk tradeoff explicit.

Total costs associated with premature mortality are determined by multiplying the VSL by the expected number of fatalities. Values obtained using this method are generally

[176] This term has been used consistently throughout the literature until ExternE introduced the term, value of prevented fatality (VPF) as a substitute (EC, 2005).

higher than the QALY and VOLY methods, which are discussed below, because VSL is not reduced to account for advanced age and/or deteriorating health status.

Impact of age and health status on premature mortality valuation

Another parameter that affects the valuation of premature mortality is whether or not the valuation should be reduced to account for people who are at an advanced age or those who have suffered a decline in health. This is a particularly important factor since the majority of air pollution impacts may cause disproportionate health damages to the elderly and the infirm. According to Schwartz (2003 cited in DSS for MOE, 2005), approximately 80% of premature fatalities associated with air pollution are elderly (65 and over). The question that is relevant is whether this age segment values the increased risk differently than younger adults (Krupnick et al., 2002). Depending on the views of the analyst, either the value of a statistical life (VSL), value of a life year lost (VOLY) or quality-adjusted life year (QALY) technique is used.

Quality-adjusted life year (QALY)

The quality-adjusted life year approach accounts for the impact of morbidity on the valuation of premature mortality. Utilizing this technique assumes that infirmity reduces the value of premature mortality since the quality of life is reduced. QALY is determined by reducing the value obtained for life expectancy by a decline in quality of life, as represented by health status. Individuals are asked to provide a utility score between 0 and 1 to measure their health status, where death receives a score 0 and perfect health receives a score of 1. Individual utility values corresponding to a person's subjective expression of their state of health is aggregated to determine society's average. This figure is used to weight life years so that the final value encompasses both morbidity and mortality considerations. It implies that unhealthy people are willing to pay less than healthy people because they derive less utility from an additional year of life (Coyle et al., 2003).

Value of Life Year (VOLY)

VOLY measures the reduction of life expectancy rather than simply the number of premature fatalities in an affected region. It is described by the following function:

VOLY = WTP for gain in life expectancy / Change in length of life expectancy

It is argued that the length of lifetime lost is more useful than the total number of people who suffer premature mortality (EC, 2005). According to Rabl (2003) this is because air pollution impacts are cumulative, VSL is distorted by the segment of the population who would die during the analysis anyways, irrespective of their exposure to air pollution. ExternE (EC, 2005, p. 44) states that:

> It is quite plausible that everybody's life is shortened to some extent by pollution, in which case every death would be a premature death due to pollution. Number of deaths is therefore not a meaningful indicator of the total air pollution mortality…Rather one has to use loss of LE which is indeed a meaningful indicator.

Total VOLY costs are determined by multiplying the average number of life years lost by the average VOLY. According to Sundqvist (2004), the premature mortality value obtained using the VOLY approach is less than VSL by about 2 orders of magnitude. The central VOLY estimate obtained by EC (2004) was €50,000 (2004 €).

Valuation study used to monetize the impacts of air pollution attributed to natural gas-fired generation

Although some of these issues are currently unresolved in the literature, the results of Krupnick et al. (2002), which have been adopted by DSS for MOE (2005), are considered to be suitable for use in this study. In 1999, the contingent valuation method was used to poll 930 Hamilton, Ontario respondents between the ages of 40 and 75 to elicit their WTP for reductions in premature mortality risk.[177] They were asked to place a value on an

[177] The study first tested respondents' comprehension and then provided them with information about trading income for reduced risk to familiarize them with the survey process. It took several hours to fill out the survey, which means that the only people that completed it were not busy and were willing to respond to small monetary incentives (which may not be representative of the population). In addition, people may have been skeptical of a health product that is not covered by health insurance or may not have understood the risks or doubted the effectiveness of the health product (Krupnick et al., 2002).

unspecified health product that was not covered by health care or insurance, which could reduce mortality risk by 1/10,000 over a ten year period.[178] The findings reveal a mean WTP figure of $368, which translates into a VSL of $3.8 million (1999 CDN$). This value is slightly more conservative than the AQVM VSL value of $4.1 million (1996 CDN$)(Chestnut et al., 1999). Among the 78 VSL studies completed before 1990 that were surveyed by Ives, Kemp and Thieme (1993) and reproduced in EC (1999a), the median VSL value is $2.7 million (1990 US), which is close in proximity to the results of Krupnick et al. (2002). Furthermore, it is within the range of €1 to €5 million observed in the literature, which is noted in ExternE (EC, 2005).

In addition to being moderate relative to other VSL studies, the findings of Krupnick et al. (2002) are utilized in this assessment (via its inclusion in DSS for MOE, 2005) for several other reasons. Of particular distinction is that it was designed specifically to measure the value of premature mortality in Ontario, thereby reflecting local demographic factors and regional preferences towards premature mortality risk. According to Krupnick et al. (2002), Hamilton respondents' age, gender and education level are representative of residents throughout the province of Ontario. Moreover, utilizing the contingent valuation method is preferable to a wage-compensation study to obtain Ontarian's WTP because it is more accurate in the context of assessing air pollution impacts (Desaigues et al., 2004). According to Desaigues et al. (2004), this particular contingent valuation questionnaire is the most relevant for premature mortality associated with air pollution.

Whether VSL, QALY or VOLY should be recognized as the optimal measure of premature mortality is unresolved in the literature at this time (Alberini et al., 2004). Krupnick et al. (2002) find that age has minimal effect on the WTP for a reduction in the risk of premature mortality until approximately 70 years of age, when it declines only slightly. Krupnick et al. (2002) reason that VSL is more suitable than VOLY or QALY claiming that, "there is no evidence that the VSL should be equally apportioned over

[178] According to the Krupnick et al. (2002), risk changes assessed in wage-compensation studies are normally of a similar magnitude.

remaining life expectancy, or that the VSL is systematically lower for persons with chronic illness" (Krupnick et al., 2002, p. 181). This finding is also supported by (Alberini et al., 2004). Since VSL still accounts for the preferences of elderly and infirm people to some extent (as they are included in the mean WTP value), the Krupnick et al. (2002) position is considered feasible and as such, there would be no need to depart from their VSL figure, which would effectively de-value the preferences of young, healthy people (who may eventually become elderly and/or infirm themselves). Moreover, Venema and Barg (2003) note that this approach is endorsed by Health Canada and Environment Canada. Since the VSL approach diverges from the VOLY approach supported by ExternE (EC, 2005), it is acknowledged that this may be a limitation.

Based on a VSL value of $3.8 million (1999 CDN$), a social discount rate of 5% and the impact data discussed above, DSS for MOE (2005) produces a value of $0.016/kWh (2006 CDN$) for the external effects of premature mortality attributed to air pollution from natural gas-fired electricity generation, which is adopted for this assessment.

However, it is worth reiterating that this result is based on the assumption that 6,447 MW of coal-fired electricity generation are replaced by natural gas. As a result, there may be a potential limitation in terms of interpolating or extending the results above or below the 6,447 MW of replacement capacity that was evaluated by DSS for MOE (2005). Since the modeling of alternate impacts is precluded from this analysis, it is unclear what effect this would have on the population and whether this would understate or overstate the results of this study.[179] Yet, Pope et al. (2002, p. 1139) note that

> Within the range of pollution observed in this analysis, the concentration-response function appears to be…nearly linear. However, this does not preclude a levelling off (or even steepening) at much higher levels of air pollution.

Consequently, the results of DSS for MOE (2005) are assumed to be linear and therefore are considered to be sufficient to represent the external effects of premature mortality linked to air pollution for the scenario evaluated here.

[179] For instance, it is possible that even as emissions are increased (decreased), the same level of impacts may be observed since the sensitive segment of the population has already been affected at the level considered by DSS for MOE (2005). Conversely, it is also possible that impacts may rise (decline) in a non-linear fashion at a different emission level.

5.3.1.3 Total computable external costs:

The total computable external costs associated with natural gas-fired electricity generation are \$0.005/kWh (climate change) + \$0.016/kWh (premature mortality associated with air pollution) = \$0.021/kWh.

5.3.1.4 Incomputable external costs associated with the natural gas fuel cycle

The following burdens are considered in the literature but are thought to be negligible relative to climate change impacts and premature mortality associated with air pollution:

- Morbidity impacts linked to smog pollutants including respiratory and cardiovascular complications, the burden on the health care system (e.g. hospital admissions, emergency room visits and doctor's office visits), productivity losses (e.g. restricted activity days and reduced productivity by sick workers) and pain and suffering (DSS for MOE, 2005).
- Impacts on the built environment such as soiling of household materials (DSS for MOE, 2005).
- Reduced crop yield (ExternE, 2004)
- Reduced visibility from air pollution (EC, 1999b)
- Upstream impacts in the natural gas fuel cycle are also estimated to be minor relative to the computable external burdens evaluated. Air pollutants and greenhouse gases emitted during facility construction, mining, gas production and transport are negligible compared to emissions from the electricity generation stage (SCS for CEA, 2005). In addition, small amounts of methane or sulphur dioxide leakage during upstream fuel cycle stages are thought to be inconsequential as well (Dones et al., 2005)
- Accidents during the mining stage and gas explosions are also thought to be insignificant relative to computable external burdens (Rabl et al., 2005)

5.3.1.4.1 Incomputable external costs associated with the natural gas fuel cycle that may be non-negligible

Ecosystem damages

A potentially non-negligible external burden in the natural gas fuel cycle that has not been reflected in external cost estimates is the impact of natural gas-fired electricity generation emissions on ecosystems (EC, 2005).[180] Data on ecosystem impacts associated with air pollution are particularly poor for burdens that affect biodiversity, forests, marine life and water quality (Chestnut et al., 1999, chapter 6).[181] In addition, the complexity and the varying degrees of resiliency that ecosystems exhibit, render such impacts difficult to quantify (ORNL & RfF, 1998). Certain pollutants that are absorbed by ecosystems at a particular scale may not be as easily digested beyond a certain threshold due to cumulative effects, leading to potentially severe and irreversible consequences.

In one well-known and highly contested study, Costanza et al. (1997) estimated the value of the world's renewable ecosystem services to be $33 trillion (1994 US$).[182] Kammen and Pacca (2004, p. 325) note that:

> Although this precise monetary valuation has been widely critiqued, the calculation has proven illustrative of the subsidy we receive from nature and the need to put human activities into a wider ecological context.

For the purpose of this assessment, however, it is necessary to measure the marginal damages to the quality of ecosystem goods and services as a result of air pollution associated with natural gas-fired electricity generation, rather than ecosystems' total value. Recently, ExternE became the first electricity externality study to evaluate such damages. The value for ecosystem damages departs from the bottom-up damage cost method to utilize the revealed preferences of European policy makers. External effects

[180] However, it is possible that in evaluating burdens associated with climate change, some of the impacts that might cause damage to ecosystems are already accounted for. However, it is unknown what proportion this amounts to.

[181] "Biodiversity refers to (1) the genetic diversity of species and populations, (2) the species diversity of biological communities (i.e., number of species of plants and animals); and (3) habitat diversity at a local, regional, or global scale" (ORNL and RfF, 1998, Report No. 4, p. D-3).

[182] This figure was obtained by extrapolating the unit area value of an individual biome and multiplying it by the biome's total area and then aggregating the results of 16 respective biomes to arrive at a total value for the biosphere.

due to emissions of sulphur dioxide, nitrogen oxides and ammonia (that were emitted from various sources including electricity generation) were estimated to cause ecosystem damages of €100 per hectare of land per year based on the costs of meeting critical load targets set by policy makers (EC, 2005).

However, the results of ExternE (EC, 2005) are not appropriate for the Ontario context for several reasons on account of site and receptor specificity. Of the three pollutants evaluated by ExternE (EC, 2005), only nitrogen oxides are appropriate for the evaluation of natural gas-fired electricity generation on Ontario. Moreover, the proximity of an affected ecosystem to an electricity generating unit and particular ecosystems' sensitivity to marginal pollution is unique, varying from ecosystem to ecosystem, making the transfer difficult. In addition, monetization involving the preferences of European bureaucrats is not readily transferable to Ontario. Clearly, valuing particular damages to ecosystems is a complex undertaking that is highly dependent on the critical loads that an ecosystem is able to absorb and the nature of the affected ecosystem itself. While data on ecosystem burdens may not be knowable, siting electricity generation units away from sensitive ecosystems can at least mitigate some of the burden, though by how much is unclear and is context specific.

Damages to built environment of cultural significance

In addition to ecosystem damages, another potentially non-negligible burden associated with the natural gas-fired electricity production is the deterioration of structures in the built environment that have cultural value (e.g. a monument or old building) as a result of air pollution. It is noted that these impacts are potentially significant as opposed to other more negligible impacts to the built environment such as the soiling of household materials. Individuals' preferences towards such impacts are thought to be insufficiently developed to yield a legitimate value for such burdens (EC, 1999a).

5.3.2 Wind fuel cycle

Since wind is naturally generated, the main emissions under consideration are produced during upstream activities, namely, in the manufacture and assembly of wind turbines (Dones et al., 2005). The production of wind turbines involves resource extraction and transport of raw materials, component manufacture, assembly and transport of components, turbine construction and turbine decommissioning. In addition, several other site and receptor-specific burdens are associated with the existence and operation of this generation alternative, such as noise and visual disturbance (EC, 1999b).

5.3.2.1 Computable external costs associated with the wind fuel cycle

The assessment of electricity externality studies is presented in Figure 5-27.[183] As with natural gas-fired electricity generation, the two most significant computable external burdens associated with the wind fuel cycle are climate change and premature mortality associated with air pollution. Unlike natural gas-fired emissions, which are emitted during electricity generation, emissions associated with the wind fuel cycle are produced during upstream fuel cycle stages.

In addition to premature mortality and climate change, various miscellaneous costs make up the remainder of the computable burdens for wind-powered electricity generation. Due to their small amount in absolute terms and relatively small proportion to total wind external cost estimates as well as their decidedly site and receptor-specific nature, the external effects associated with noise disturbance, visual intrusion and land use are grouped together into one category termed miscellaneous external burdens.[184]

[183] Refer to Appendix C (iii) for a more comprehensive list of computable external burdens for each source.
[184] The external costs of these burdens are included in the evaluation in order to satisfy the 80% non-negligible external cost criterion laid out in section 4.2.3.2.

Figure 5-27: Assessment of computable external burdens in the wind fuel cycle

Study	Monetized premature mortality costs associated with air pollution, as a percentage of computable external costs (%)	Monetized climate change costs, as a percentage of computable external costs (%)	Monetized miscellaneous external costs, as a percentage of computable external costs (%)	Other external costs as a percentage of computable external costs (%)
Rowe et al. (1995)	n/a	n/a	100%	0%
EC (1999b) Germany	56%	28%	7%	7%
EC (1999b) Denmark	22%	34%	25%	20%
EC (1999b) Spain	83%	13%	1%	1%
EC (1999b) Greece	36%	6%	54%	1%
EC (1999b) Norway	79%	20%	0%	2%
EC (1999b) UK	n/a	15%	7%	76%
Average	55%	19%	28%	16%

Sources: as indicated

Note (a): individual study percentages may not add up to 100% due to rounding.

Note (b): the sum of the averages does not add up to 100% due to the presence of n/a (not applicable) for particular external burdens. The term n/a is used to signify that the original authors decided not to evaluate a particular external burden as opposed to estimating a value of zero.

It is noted that since wind turbine technology has developed at a fast pace, studies that were conducted even a few years ago may not be sufficient to capture data that are representative of new wind turbines. For example, most data in the literature are based on the assessment of turbines with an approximate capacity of 500kW – 1 MW, as opposed to the turbines that are utilized in wind farms today that are generally constructed to be 1.5 MW and larger. It is anticipated that this should not be a significant drawback, but it does reflect a limitation of the data.

5.3.2.2 Power conversion stage

5.3.2.2.1 Noise costs

Although this burden is associated with the power conversion stage of the fuel cycle, the external effects of noise are quantified with other "miscellaneous" burdens in the following section.

5.3.2.3 Non-power conversion stage

5.3.2.3.1 Premature mortality costs from air pollution

Atmospheric emissions are produced during upstream stages of the fuel cycle. Such activities include the extraction of raw materials and the manufacture and assembly of turbines and turbine components, with the construction of the steel tower and nacelle generating the majority of emissions (Shleisner and Nielson, 1997; Frankl, 2004). These activities require electricity use and transport of materials, which are assumed to cause atmospheric emissions. As with natural gas, such emissions are attributed to premature mortality. However, in absolute terms, emissions produced in the wind fuel cycle are small and are considerably lower than emissions associated with fossil fuel-based electricity generation (i.e. they would be considered negligible for the other generation alternatives under study). Yet, proportionally, they are responsible for the largest computable external cost in the wind fuel cycle.

For this external burden, ExternE (Schleisner and Nielson, 1997) derives an estimate of \$0.00238/kWh, which is assumed to be applicable for the purpose of this assessment.[185] It is deemed suitable since many turbines erected in Ontario originate from Denmark, where an industry-leading turbine developer is based (McCulloch et al., 2000). Moreover, the dose-response function used to evaluate the impacts of air pollution on Danish receptors was derived from an earlier version of the same study that provided the dose-

[185] This result was derived for 18 500 kW Vestas on-land turbines at the Fjaldene Wind Farm in Denmark. Electricity used for construction and assembly was assumed to be generated from coal and natural gas. The Ecosense Model developed by ExternE researchers was employed to model dispersion and impacts based on the dose-response function for chronic mortality from Pope et al. (1995). Valuation of such impacts was based on a social discount rate of 3% and a VSL value of \$5.4 million, which was derived from a meta-analysis of various European and North American valuation studies.

response function in the evaluation of premature mortality associated with natural gas-fired electricity generation (Pope et al., 1995). The VSL applied in this case is 20% higher than the VSL used to evaluate the external costs associated with natural gas-fired electricity generation, which is assumed to be a reasonable divergence due to the different preferences of the receptors. However, it is acknowledged that the evaluation for wind was performed for turbines with a capacity of 500 kW, as opposed to the 1.8 MW turbine capacity that is assumed to exist for the incremental units installed in Ontario. It is unclear what effect this would have on the results because the emissions per kilowatt-hour of electricity generated by the larger wind turbines may be altered.

5.3.2.3.2 Climate change costs

In the interest of brevity, various issues regarding climate change including the potential biophysical and social impacts, the proposed mitigation and adaptation strategies and the previous attempts to quantify the costs of climate change impacts, which have already been discussed in section 5.3.1.2.1, will not be re-examined here. The greenhouse gas emissions permit cost of \$15/tonne of CO_2-eq (in real terms) that was applied to the greenhouse gas emissions associated with natural gas-fired electricity generation remains applicable to turbine development and construction, since greenhouse gases have the same effect regardless of where and how they are produced.

Upstream activities associated with the wind fuel cycle produce 0.000014535 tonnes of CO_2-eq/kWh (Schleisner and Nileson, 1997).[186] Therefore, climate change costs associated with the wind fuel cycle are estimated to be \$0.00022/kWh.[187]

[186] This estimate is generally consistent with GHG emissions data found in other reports. For example, McCulloch et al. (2000) (0.000013 tonnes CO_2-eq/kWh); Frankl et al (2004) (0.0000117 tonnes CO_2-eq/kWh); and OPA (2005) (0.000012 tonnes CO_2-eq/kWh).

[187] Calculation: \$15/tonne of CO_2-eq x 0.000014535 tonnes CO2-eq/kWh = \$0.00022/kWh (Schleisner and Nielson, 1997). GHG emissions per unit are based on wind-powered electricity generation with a 16 m/s wind speed (capacity factor is unavailable but is assumed to be in the upper range of capacity factors in the literature based on this wind speed (Schleisner and Nielson, 1997).)

5.3.2.3.3 Miscellaneous costs

Noise disturbance is defined as “unwanted or damaging sound” (EC, 2005, p. 69). Wind turbines generate noise as blades rotate to produce electricity. According to EC (2005), such noise may cause hypertension, sleep disturbance, communication disturbance and annoyance. Alternatively, visual intrusion refers to the aesthetic interruption of the natural landscape. External effects of visual intrusion are associated with a decrease in the amenity value or enjoyment level of a particular view (EC, 1999a). Consequently, noise and visual disturbance may cause social acceptability concerns for wind-powered electricity generation. Despite a survey conducted by the Canadian Wind Energy Association (CanWEA), in which 92% of respondents expressed support for local wind development, there was a segment of the population that did not support local electricity generation from wind, at least partially due to these burdens (CanWEA, 2005). For example, residents of the municipality of Grey Highlands in Ontario protested the establishment of wind turbines in their community and there has also been significant opposition to an off-shore wind farm near the coast of Cape Cod, Massachusetts for similar reasons (Blue Highlands Citizens Coalition, 2006; Cape Wind, 2006). The issue of social acceptability with respect to wind power has been referred to as a NIMBY (i.e. not in my backyard) problem since individuals may not be opposed to wind power in general, but would prefer if turbines were not erected in their community.

The result of the CanWEA (2005) survey illustrates how noise disturbance and visual intrusion can be highly site-dependent and receptor-specific. The context in which turbines are seen or heard can have a considerable impact on the measurement of their external effects. According to Huron Wind (2006), newer turbine designs exhibit a reduction in noise such that at a distance of 250 metres away the noise level is equivalent to that of a regular conversation. Notwithstanding the ability to evaluate decibel levels, the evaluation of noise is also subjective in many respects. For instance, the level of background noise is an important factor in determining the magnitude of the external burden. It is recognized that the noise from a turbine in a loud industrial area is not likely to be considered as disruptive as is the noise from a turbine located near an otherwise tranquil nature trail. (EC, 1999a). Moreover, constant noise is thought to be less annoying than sharp sporadic increases in noise (EC, 2005). And, what is considered noise disturbance by one individual will not necessarily be regarded as unpleasant by another (i.e. the noise is "in the ears of the beholder").

Similarly, some people like the appearance of wind turbines, while others are indifferent or view them as a visual intrusion (i.e. visual intrusion is dependent on the preferences of people in the local community) (Shleisner and Nielson, 1997). In addition, the site itself plays a role in whether external effects exist. According to (EC 1999a, p. 454):

> Visual intrusion is a local scale impact. Because of the heterogeneous nature of landscape the visual effects of the same technology in different places can vary greatly. The importance of local variation is increased by the great importance attached to some rural landscapes. The nature and strength of this valuation is clearly a matter of considerable complexity.

As a result, noise and visual burdens can be mitigated somewhat by prudent siting and planning techniques (EC, 2005). In many cases, noise can be reduced by maintaining an adequate buffer between turbines and receptors and visual disturbance can be mitigated by blending turbines into their surroundings or locating them sufficiently away from those who have an aversion to their appearance (Frankl, 2001). However, while site and receptor-specific burdens can be minimized to some extent, external effects may remain.

Quantifying noise and visual disturbance for each potential wind site in Ontario would require data on the burdens themselves, information about the size of the affected population and their proximity to the wind turbines and the receptors' preferences towards such burdens. Due to the lack of refereed studies regarding Ontario-specific data, results from ExternE are utilized.[188]

Various countries participating in the ExternE National Implementation Project estimated the external costs of noise (EC, 1999b). For example, the noise level at the Fjaldine wind farm in Denmark was 13.6 dB at a distance of 3 km, which produced an external cost of

[188] The lack of site and receptor data for these burdens is acknowledged as a limitation of this analysis. However, given that such costs are thought to be extremely low in absolute terms, this approach is assumed to be a reasonable point of departure from the methodology outlined in Chapter Four.

$0.00004/kWh (Schleisner and Nielson, 1997).[189] However, ExternE (EC, 1999a) notes that in the absence of site and receptor data, an external cost of $0.00018/kWh can be used to represent the external cost for noise disturbance from wind turbines. Consequently, this figure is incorporated into this analysis.

As for an estimate of visual intrusion, Rowe et al. (1995) find that there is a lack of consistent valuation estimates due to the context specific nature. Schleisner and Nielson (1997) estimate the external cost of visual intrusion to be $0.003/kWh.[190] Although this estimate is not necessarily appropriate to use for the Ontario context, it will be adopted here because it is assumed to be of a reasonable order of magnitude.[191]

In addition, land use is another context specific external burden associated with the wind fuel cycle. Although wind farms can take up a significant amount of land mass depending on their size, the external effects from land use are uncertain since the land between the turbines may be utilized for other purposes. For example, the Huron wind farm in Tiverton, Ontario uses only 5% of the land where its turbines are erected for the turbines themselves, leaving 95% for agricultural use (Demetriou and Chubbuck, 2001). OWPTF (2002, p. 14) notes in particular that:

> Wind energy is popular with farmers because the wind turbines provide a consistent source of revenue and take very little out of production. Land can be cultivated within a few feet of the base of the turbines. The machines do not disturb livestock. Wind parks can also be compatible with other land uses like forestry and recreation. On average, a wind farm will use between 1% and 2% of the land base in a wind park, with 12 to 24 turbines for every square kilometre.

A concern with respect to land use is whether the turbine location will have an adverse effect on a local ecosystem. Again, it is noted that external effects can be mitigated by

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[189] The external effects associated with noise were calculated using the Noise Depreciation Sensitivity Index, which measures the average change in property prices per decibel increase. This is a revealed preference approach known as the Hedonic Price method, which evaluates WTP to avoid noise by assessing house prices relative to where the noise occurs (EC, 2005).

[190] This estimate also determines WTP based on the hedonic price method, evaluating homes within a radius of 1,500 metres of the wind farm.

[191] Again, since miscellaneous burdens are believed to be extremely small in absolute terms and their magnitude would likely be considered negligible for the other fuel cycles under study, there is believed to be a wide margin of error before the overall results would be appreciably affected.

judicious planning. Rowe et al. (1995) estimate the external cost associated with this burden to be \$0.00001/kWh, which is utilized here.

In sum, miscellaneous computable external costs are estimated to be \$0.00319/kWh.[192]

5.3.2.4 Total computable external costs for the wind fuel cycle

The computable external costs associated with wind-powered electricity generation are \$0.00238/kWh (premature mortality associated with air pollution) + \$0.00022 (climate change) + \$0.00319/kWh (miscellaneous) = \$0.00579/kWh.

5.3.2.5 Incomputable external costs associated with the wind fuel cycle

The following external burdens are considered in the literature but are thought to be negligible relative to the external effects discussed above:

- Bird fatalities are thought to be negligible as long as turbines are strategically located away from known migratory paths of birds (EC, 2005)
- The burdens associated with accidents in the wind fuel cycle are estimated to be quite small (ExternE, 2004)

5.3.2.5.1 Incomputable external costs associated with the wind fuel cycle that may be non-negligible

<u>Emissions associated with transportation costs</u>

It should be noted that since the domestic production of wind turbines is negligible in Ontario, turbines, or at least some components, may have to be imported, sometimes from as far away as Denmark, which is home to one of the largest turbine developers in the world. Since the previous calculations did not include transportation outside of

[192] Calculation: \$0.00018/kWh (noise) + \$0.003/kWh (visual disturbance) + \$0.00001/kWh (land use) = \$0.00319/kWh.

Denmark, the emissions associated with transporting the turbines to Ontario may be non-negligible and this should be investigated further.

5.3.3 Nuclear fuel cycle

The fuel cycle for nuclear-powered electricity generation in Ontario is highly complex.[193] Uranium from northern Saskatchewan is used to produce electricity at CANDU nuclear reactors in Ontario. Before being shipped to Ontario, uranium is mined and milled. For mining, open-pit and underground processes are utilized. The uranium ore is then recovered at a uranium mill located in close proximity to Wollasten Lake in Saskatchewan, where it is ground and treated with sulphuric acid in a chemical leaching process. The "sand-like tailings" that are produced by the milling process are transported to the tailings long-term management site in Key Lake, Saskatchewan, where they are submerged in water in an underground pit. The uranium (known as yellow cake or uranium oxide by the time it has reached this stage) is then transported by truck to Blind River, ON to be refined by utilizing a chemical process that produces natural uranium trioxide (UO_3). From there, the UO_3 is sent to Port Hope, ON for conversion into uranium dioxide (UO_2). The fuel then undergoes a fabrication process at plants in Port Hope, Toronto or Peterborough, which creates the pellets for fuel rod bundles that are used in nuclear reactors during the electricity generation stage. During electricity generation, deuterium oxide – also known as "heavy water" – is used as a moderator and coolant and this also must be produced beforehand and is eventually released back into one of the Great Lakes that the reactor is situated adjacent to. In addition, the fuel cycle also includes the construction of the power plant and the other facilities involved in the fuel cycle. After electricity is generated at the power plant, the resulting high-level waste is stored on-site in underwater containers and is then transferred to dry storage on-site on an interim basis. Low-level and intermediate-level waste is also stored at the facility where it is produced. Finally, a long-term waste disposal/containment and decommissioning phase

[193] The Candu technology fuel cycle exhibited in Ontario is consistent with fuel cycles using other nuclear reactor technologies such as light water reactors and pressurized water reactors in that it is associated with mining, milling, refining, conversion and waste management. However, the Candu fuel cycle does not involve an enrichment process or spent fuel reprocessing (SENES for OPA, 2005).

will be carried out for intermediate-level and high-level waste. This will involve the construction of a long-term storage facility and transportation of high-level waste to the repository (OPA, 2005; SCS for CEA, 2005).

5.3.3.1 Computable external costs associated with the nuclear fuel cycle

Public health costs associated with radioactive emissions from several non -power conversion fuel cycle stages is the predominant computable external burden associated with the nuclear fuel cycle. This is followed by the external costs associated with severe nuclear accidents. Results of the computable burden assessment are presented in Figure 5-28.[194]

[194] Refer to Appendix C (iii) for a more comprehensive list of computable external burdens for each source.

Figure 5-28: Assessment of computable external burdens in the nuclear fuel cycle

Study	Monetized public health costs associated with radioactive emissions from non-electricity generation fuel cycle stages, as a percentage of computable external costs (%)	Monetized costs associated with nuclear accidents, as a percentage of computable external costs (%)	Other external costs, as a percentage of computable external costs (%)
Ottinger et al., (1990)	n/a	99%	0%
Chernick et al., (1993)	15%	85%	0%
Rowe et al., (1995)	7%	50%	43%
Berry et al. (1998)	87%	n/a	12%
ORNL & RfF (1998)	8%	54%	38%
Spadaro & Rabl (1998)	81%	0%	19%
EC (1999b) Belgium	84%	5%	11%
EC (1999b) Germany	76%	0%	21%
EC (1999b) Netherlands	99%	1%	0%
Average	57%	37%	24%

Sources: as indicated

Note (a): individual study percentages may not add up to 100% due to rounding.

Note (b): the sum of the averages does not add up to 100% due to the presence of n/a (not applicable) for particular external burdens. The term n/a is used to signify that the original authors decided not to evaluate a particular external burden as opposed to estimating a value of zero.

5.3.3.2 Power conversion stage

5.3.3.2.1 Potential nuclear accident costs

Since the inception of nuclear-fired electricity generation there have been two major nuclear accidents: one at Three Mile Island (TMI) in the United States in 1979 that was successfully contained and another that produced more significant consequences at Chernobyl in Ukraine in 1986. Despite the occurrence of these incidents, the probability that a severe nuclear accident will take place in the future remains very low. However, the consequences, as these two incidents attest, have the potential to be catastrophic.[195] Since nuclear operators are required by the Canadian Nuclear Safety Commission to obtain insurance that covers the costs associated with a large-scale nuclear accident, some of the external effects are internalized (*Canadian Nuclear Liability Act*, R.S., 1985, c. N-28). However, due to the legislation that limits nuclear operators' liability on such impacts to $75 million, some potentially significant external costs that could be incurred by the public are not covered by insurance, and thus some of the external effects are not internalized.[196]

Costs are quantified by estimating the risk-based expected damage of a potential accident (EC, 1999a). This is carried out by estimating the probability that a severe accident will occur and the probability that containment systems will fail and then multiplying each scenario by the estimated cost associated with a potential incident. It is assumed that in the event of an accident, containment systems can either experience a massive containment failure (MCF), in which a large amount of radioactive emissions are released from the reactor as in the case of Chernobyl, or a limited containment failure (LCF), in which a very small amount of radionuclides are released, as in the case of Three Mile Island (ORNL & RfF, 1998). The expected value of an accident is equal to the summation of each scenario, which is given by the following expression:

[195] This discussion on accidents is confined to large-scale accidents only since non-large scale accidents involving non-radiological health and environmental impacts are considered to be negligible (OECD NEA, 2003a). However, it is noted that large-scale accidents in the nuclear fuel cycle can also occur during the waste management phase (ORNL & RfF, 1998). Although precautions will be taken in preparation for long-term containment, the risk of waste leakage into ground water or an accident involving transport between containment facilities exists (SCS for CEA, 2005). ORNL & RfF (1998) speculate that the probability of a waste management accident is likely to be greater than an accident at the reactor, noting that shipping casks will probably feature less effective containment than at the reactor site. However, according to MIT (2003, p. ix), "We know little about the safety of the overall fuel cycle, beyond reactor operation." Potential accidents in the waste management stage of the fuel cycle receive little attention in the literature compared to reactor accidents. Therefore, although waste management accidents may be non-negligible, only accidents at the reactor are evaluated here.

[196] This is not unlike the proposed limit on the price of greenhouse gas emission permits that the Government of Canada has previously indicated it will cover above $15/tonne of CO_2-eq. In both situations, only a subset of the external burden would be internalized.

Expected value = (probability that accident occurs x probability of MCF x cost associated with MCF) + (probability that accident occurs x probability of LCF x cost associated with LCF)

The probability of a nuclear accident is in the range of 0.000001 to 0.0000001 (EC, 2005). If available, a plant-specific probabilistic safety assessment (PSA), which measures the potential for radiological materials to breach the containment area of the reactor, could be used to determine the probability of a particular reactor accident.[197] A PSA evaluates a multitude of scenarios in which safety malfunctions could result in damages (for instance, loss of coolant, computer breakdown, break in pressure tube, etc.) and assigns each scenario an impact and a probability.[198] According to a PSA conducted by KEMA, the probability of a large-scale reactor accident for a Candu generating unit is 0.0000046 (Snell and Jaitly, 2001).

Next, the probability that a significant amount of radioactive emissions are released from the reactor core in the event of a severe accident, which is contingent on the effectiveness of the reactor's containment systems, is required. Should a severe accident occur, it is assumed that the probability of a massive containment failure is 0.26 and the probability of a limited containment failure is 0.74 (US NRC, 1990 cited in ORNL & RfF, 1998).[199]

The only massive containment failure in the history of nuclear-fired electricity generation occurred at Chernobyl, resulting in significant consequences. Although such damages are affected by context specific variables like the magnitude of the release, the size and characteristics of the receptors (i.e. population and environment) and local and regional

[197] PSA is also known as a probabilistic risk assessment (PRA) (ORNL & RfF, 1998).
[198] Of course, probabilistic safety assessments can only evaluate accident scenarios that have been considered and it is possible that an actual accident in the future may not have been previously considered in a PSA. As a result, the probability of an accident occurring derived from a PSA may be understated (Ottinger et al., 1990).
[199] It is noted that these probability estimates have been made for pressurized water reactors (PWR) in the United States and hence they are not specific to Candu reactors. PWR and Candu reactor models share similar safety features such as containment chambers, cooling systems and automated shutdown systems. However, according to AECL (2006b, p. 1), "CANDU is the only reactor where failures of both primary and emergency cooling systems will not result in a fuel melt". The extent to which this, or any other variation in the design of PWR and Candu reactors, has on the applicability of the NRC probability estimates for Candu nuclear reactors is uncertain.

dispersion patterns, various consequences that affected the area surrounding Chernobyl can be assumed to occur in the event of a severe accident involving an Ontario nuclear reactor (ORNL & RfF, 1998). For instance, it is estimated that a Chernobyl-like accident would be responsible for acute and latent fatalities from radiation and increases in non-fatal illnesses such as non-fatal thyroid cancer, hereditary genetic effects, cataracts, and psychological distress (IAEA, 2006c). In addition, countermeasures to mitigate human health burdens such as evacuating and relocating the population in close proximity to the reactor, providing temporary accommodations and food, decontaminating the most affected areas and performing ongoing monitoring and research would be required (OECD NEA, 2003a). A release of radioactive emissions would also cause damage to agriculture, likely leading to widespread food bans. Forestry and marine life would also be adversely affected (Eeckhoudt et al., 2000). Moreover, interrupted economic activity could potentially have a disastrous effect on local and regional employment levels and could also have a great impact on the national economy since Ontario in general and Toronto in particular (which is situated within 70 km of the Pickering and Darlington Stations and 250 km from the Bruce Station) is the financial and industrial hub of the country (OPG, 2006c; Bruce Power, 2006b).[200]

Given the scale of the impacts and the nature of the consequences, deriving an appropriate estimate for the cost of a large-scale nuclear accident is a complex endeavor. However, the cost estimates derived for previous accidents can be utilized. For this assessment, a cost estimate of the Chernobyl accident is used as a proxy for the cost of a massive containment failure, whereas a cost estimate for the accident at Three Mile Island is assumed to be representative of the cost of a limited containment failure. According to ExternE (ExternE, 2004), the estimated cost of the Chernobyl accident was approximately $473.3 billion, while the cost of the Three Mile Island accident was $7.6 billion. The large difference between the two accidents is that unlike Chernobyl which resulted in a massive containment failure, the safety systems at TMI were effective as the core experienced a partial meltdown and consequently, the accident did not cause any

[200] It is assumed that any new reactors will be built on an existing nuclear site adjacent to previously built reactors since preliminary steps for conducting an environmental assessment for new units on existing nuclear sites have been initiated (MOE, 2006b).

fatalities. The major costs of TMI, however, were the lost generating unit, the evacuation of people within a 5-mile radius, decontamination of the site and research and monitoring costs (US NRC, 2005).

Eeckhoudt et al., (2000) note that the population living within 3,000 km of a large-scale accident would be disturbed and people living inside a 100 km radius from the accident would be most severely affected. According to IAEA (2006c), the regional areas that were most affected by the Chernobyl accident were located in Ukraine, Belarus and Russia and the people were primarily based in rural communities. In sum, approximately five million people were located in areas deemed contaminated and of this total, 336,000 had to be evacuated (IAEA, 2006c). Since the Greater Toronto Area alone consists of 4.7 million people located in a predominantly urban and suburban environment and two of the three reactor sites are within 70 km of Toronto, it is assumed that the Chernobyl estimate and the TMI estimate, which is located in a rural area in Pennsylvania, are applicable for this context (Statistics Canada, 2001; OPG,2006c).[201]

As noted above, nuclear operators are required to purchase insurance that covers $75 million of the total cost associated with a nuclear accident. Thus, this figure must be subtracted from the cost estimate to determine the portion of costs that are external. Given this, the revised estimated costs become $473.2 billion for the MCF scenario and $7.5 billion for the LCF scenario.

Adopting these cost figures along with the probabilities discussed above produces an external burden of $591,532/reactor year, which is divided by the number of kWh

[201] The Bruce Nuclear Station is located slightly further away from Toronto than the other sites at a distance of approximately 250 km. Its closest major metropolitan centres are London and Barrie with populations of 336,000 and 100,000, respectively (Statistics Canada, 2001). It is assumed that external costs associated with a nuclear accident are of the same magnitude regardless of which reactor experiences an accident. In reality, however, the impacts of such an incident are likely to be more severe if it occurring at Pickering or Darlington, since there are more people in the immediate vicinity. Thus, the external costs associated with a nuclear accident derived here are probably slightly overstated.

expected on an annual basis in Ontario to produce an external cost of $0.000119/kWh, expressed in real terms.[202]

However, this estimate may not adequately reflect the level of risk aversion held by the public (Eeckhoudt et al., 2000). This is because the average "lay" person is believed to regard the probability of a large-scale nuclear accident as more likely than an estimate made by an expert (who still bases some part of the estimate on judgment, rather than on objective data) (EC, 2005). However, while expert assessment may be more accurate, it is each individual's WTP that determines the collective preference of society and hence whether nuclear accident risk is socially acceptable. Moreover, there may also be a social dimension of risk connected with a large-scale accident beyond the risk that individuals consider for themselves (i.e. concern for the public in general) (Eeckhoudt et al., 2000).

It appears that individuals are more averse to accidents that have a very low probability of occurrence and catastrophic consequences than vice versa, a scenario which ExternE (EC, 2005) refers to as "Damocles' risks". Therefore, since fear of a large-scale nuclear accident appears to be higher than various expected damage estimates in the literature, external cost estimates for severe nuclear accidents should be increased to account for such risk aversion (Eeckhoudt et al., 2000). Currently, however, the issue of how the public perception of accident risk should factor into the assessment is unresolved. Various attempts to integrate a risk aversion premium have been "ad hoc and without proper empirical theoretical foundations" (EC, 1999a, p. 110).

Although a lack of consensus for the appropriate risk aversion premium exists, EC (2005) notes that the work by Eeckhoudt et al. (2000), in which a multiplying factor of 20 times the external cost of a severe nuclear accident is derived, is considered to be the most suitable to date and is implemented here.[203]

[202] Calculation: (0.0000046 x 0.26 x $473.2 billion) + (0.0000046 x 0.74 x $7.5 billion) = $591,532/4,966,920,000 kWh = $0.000119.

[203] The multiplying factor of 20 derived by Eeckhoudt et al. (2000) corresponds with a 1% release from the core and relative risk aversion coefficient of two.

Adopting a multiplying factor of 20 produces an external cost for risk-based expected damage associated with a severe nuclear accident of \$0.0024/kWh in real terms.[204] However, it is acknowledged that establishing a consensus for the appropriate risk-aversion premium with respect to a severe nuclear accident remains a work in progress and further research is required in this area (Eeckhoudt et al., 2000; EC, 2005).

5.3.3.3 Non-power conversion stage

5.3.3.3.1 Human health costs associated withradioactive emissions

Radioactive emissions causing public health impacts are responsible for more than half of the average computable external burdens among the studies assessed.[205] Although some radioactive emissions occur during electricity generation, these are negligible relative to other fuel cycle stages. In particular, the majority are released during mining and milling and reprocessing (Chernick et al. 1993; IER, 1997; ORNL & RfF, 1998). However, since reprocessing is not part of the Candu fuel cycle, its corresponding impacts are omitted from this assessment. Consequently, only the external effects of radiological emissions attributed to mining and milling are evaluated here.

There are not any transferable electricity externality studies in the literature covering the Candu nuclear fuel cycle.[206] However, the results of IER (1997) are considered suitable for this analysis despite the fact that it evaluates the external costs of pressurized water reactors in Germany. This is because the mining and milling stages of the German nuclear fuel cycle are carried out at Key Lake, Saskatchewan – a characteristic shared with the Ontario nuclear fuel cycle.

[204] Calculation: 20 x \$0.000119/kWh = \$0.0024/kWh.
[205] The Nuclear Energy Agency (OECD NEA, 2003b, p. 49) states that “Radiation is energy travelling through space or matter in the form of sub-atomic particles or electromagnetic waves. Radioactivity is the spontaneous change in nucleus of an unstable atom that results in the emission of radiation...Radioactive atoms are often called ‘radionuclides’ or ‘radioactive isotopes’ of the relevant chemical element”.
[206] It is noted that Chernick et al. (1993) is not transparent enough to utilize here and Ontario Hydro’s external cost assessment (as discussed in US EPA, 1996) is not available to the public, which precludes its use.

Source

Radon gas (Radon-222) is the key emission released during uranium mining and milling. Based on data from UNSCEAR (1993)[207], IER (1997) reports that mining processes emit 18.8 terabequerel (a measure of units of radioactivity) per terawatt-hour (TBq/TWh). Milling, on the other hand, generates emissions of 0.11 TBq/TWh, while mill tailings in operation result in 1.1 TBq/TWh.[208] Once mill tailings have been produced they are placed under water in a underground pit to minimize the release of radon gas.[209] However, such tailings still generate emissions of 0.0011 TBq/TWh.[210]

Dispersion

To determine what the impacts of the radioactive emissions are, they must be converted into collective population dose as measured in Sieverts (man.Sv) (EC, 1999a).[211] Due to the long duration of radionuclides, small annual increases in radioactive emissions can accumulate to be significant in the future, which is why collective dose is evaluated over a timeline of 10,000 years (EC, 1999a). Consequently, radioactive emissions associated with mining and milling activities produce a collective dose of 16.3 man.Sv/TWh (IER, 1997).

Dose-response function

Human health impacts of radioactive emissions are then based on dose-response functions developed by the United Nations Scientific Committee on the Effects of Atomic Radiation (UNSCEAR, 1993). Such impacts may be caused by inhalation of atmospheric radionuclides and by ingesting contaminated food (EC, 1999a). According to these data sources, the expected occurrence among the affected population over a period

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[207] The United Nations Scientific Committee on the Effects of Atomic Radiation "has the United Nations mandate for sources and effects of ionizing radiation, is a prime source of information on the radiological aspects of the nuclear fuel cycle" (SENES for OPA, 2005, p. 7-2).

[208] This is based on an emission rate of 3.7 $Bq/m^2/s$ (release duration of 5 years) (IER, 1997).

[209] Mill tailings are stored at one of three active mill tailings sites in Saskatchewan (IAEA, 2003).

[210] This is based on an abandoned mill tailings emission rate of 3 $Bq/m^2/s$ (release duration of 10,000 years) (IER, 1997).

[211] According to OECD NEA (2003b, p. 51), "radiation exposure (also referred to as 'dose') is measured in grays (Gy). One gray is defined as an absorption of radiation which deposits one joule of energy in one kilogram of material…The unit used to measure this biological significance is the sievert (Sv). The sievert is equal to the amount of energy deposited, in grays, multiplied by the relevant weighting factor; the higher the factor, the greater the reckoned damage".

of 10,000 years is 0.05/man.Sv for fatal cancer, 0.12/man.Sv for non-fatal cancer and 0.01/man.Sv for severe hereditary (i.e. genetic mutation) effects (EC, 1999a).[212] Thus, the impacts based on these dose-response functions for mining and milling activities are 0.82 fatal cancers/TWh, 1.9 non-fatal cancers/TWh and 0.16 cases of hereditary effects/TWh (IER, 1997).

<u>Monetary valuation</u>

A VSL of $5.4 million is applied to each fatal cancer, which is also thought to be appropriate for cases of hereditary complications. Non-fatal cancer is valued at $0.8 million (IER, 1997). The figure used for VSL is similar to that used for premature mortality associated with natural gas but differs slightly due to the different preferences of the population that was evaluated. At the time of evaluation, ExternE, utilized VSL rather than VOLY, which is currently used. A 0% social discount rate was used to determine the costs of external burdens that are expected to be incurred in the extremely long-term. Without doing so, such long-term radiological impacts would be significantly reduced due to the effects of discounting. ExternE (EC, 1999a, p. 45) notes that it is not uncommon for government policy to have a lower discount rate for "very long term" projects. Although research has shown that it is legitimate for the long-term discount rate to decline over time, a discount rate of 0% may not be justified (OECD NEA, 2003a). While this approach may not necessarily be empirically valid, it is assumed to be a reasonable point of departure, since the external burdens are qualitatively significant and would otherwise be considered negligible. Consequently, the results of IER (1997) are incorporated, but are considered to be an upper bound.

Consequently, health costs associated with radioactive emissions from mining and milling in the nuclear fuel cycle are estimated to be $0.0044/kWh for fatal cancer,

[212] Impact results are based on a number of assumptions. For instance, impacts caused by radiation exposure are thought to be linear without threshold, the dose-response function is expected to stay constant over time, the proportion of cancers that end in fatality is believed to remain the same as the current level. Moreover, it is noted that the biological effects of radiation from small doses of radiation are inherently uncertain due to the fact that the concentration-response functions are based on high individual doses and have to be interpolated since average individual doses are very small (OECD NEA, 2003b).
ExternE (1999a, p. 208) notes that "In spite of these drawbacks, it was decided that within the project-wide guidelines followed by all fuel cycles, this type of risk assessment methodology was required".

$0.0015/kWh for non-fatal cancer and $0.0009/kWh for severe hereditary effects, which total $0.0068/kWh (IER, 1997).

5.3.3.4 Total computable external costs associated with nuclear-fired electricity generation

The total computable external costs associated with nuclear-fired electricity generation fuel cycle are $0.0024/kWh (severe nuclear accidents) + $0.0068/kWh (human health costs associated with radioactive emissions) = $0.0092/kWh.

5.3.3.5 Incomputable external costs associated with the nuclear fuel cycle

The following external burdens are considered in the literature but are thought to be negligible relative to the computable external costs discussed above:

- Impacts of radioactive emissions on ecosystems (EC 1999a).
- Radioactive emissions from other fuel cycle stages other than mining and milling (IER, 1997).
- Greenhouse gas emissions and conventional air pollutants that are generated at several fuel cycle stages (e.g. the construction of facilities, mining and transportation between stages) (Rabl and Dreicer, 2002).
- Although a substantial amount of water is used in reactors as a coolant and moderator, the impact on marine life is thought to be small. Liquid radiological releases are similarly believed to be negligible (EC, 1999a; Golder Associates, 2006).

5.3.3.5.1 Incomputable external costs associated with the nuclear fuel cycle that may be non-negligible

Several potentially significant burdens remain incomputable in the nuclear fuel cycle (van Horen, 1996; Owen, 2006). In particular, the external cost of risks associated with a non-reactor accident, a potential terrorist attack and nuclear proliferation are not reflected in external cost estimates in the literature. According to ExternE (EC, 1999b, p. 33), "[t]hese omissions may well be significant and therefore should be clearly noted in any assessment".

Non-reactor accidents

As discussed in section 5.3.3.2.1., there is little known about accidents during the transport or management of high-level nuclear waste (MIT, 2003).

Terrorist attack

The potential for a nuclear generating unit to be the target of a terrorist attack exists and the probability of such an occurrence is distinct from the probability of an accident. For instance, in 2005, police averted a potential attack on a nuclear plant in Australia (CNN, 2005). Due to the considerable uncertainty with respect to the likelihood of a terrorist attack, it is ostensibly impossible to estimate at this time.

Nuclear proliferation

Nuclear proliferation refers to the "spread and re-designation from the sector of civil nuclear power to militarily used nuclear energy" (EC, 1999a, p. 467). Proliferation risk arises due to the fact that the same technology used for electricity generation can be used for weapon making. Nuclear weapons are produced in two ways: using highly enriched uranium (enrichment option) or using weapons-grade plutonium (reprocessing option).[213]

Diverting nuclear technology away from peaceful purposes towards military applications involves geopolitics, economic and security concerns, and ethical and moral viewpoints. ExternE (EC, 1999a, p. 467) notes that:

[213] Candu technology does not involve enrichment or reprocessing activities, so the materials utilized are not weapons-grade. However, the prospect exists that Canadian technology could be exported to another nation that could modify its use for proliferation at some time in the future. Nuclear weapons testing by India in the 1990s using commercial nuclear technology that originated from Canada in the 1960s is an ominous example of such a possibility (Thomas, 2005).

> The statistical likelihood of proliferation increases with each additional civilian nuclear fuel cycle, in particular with each uranium enrichment or spent fuel-reprocessing facility. The exact degree of likelihood depends on many, diverse, and complex factors, of which the technological aspects might be the easiest to evaluate.

The Treaty on the Non-Proliferation of Nuclear Weapons (NPT), to which Canada is a signatory, was established in 1970 to restrict countries from obtaining nuclear weapons.[214] However, the NPT does not preclude countries that already have weapons from using them. Moreover, it has not stopped nuclear technology-equipped nations from exporting the technology to non-NPT countries for commercial purposes, nor does it eliminate the possibility of smuggling to or theft by states or groups who could use the nuclear technology for weapons of mass destruction (EC, 1999a). The International Atomic Energy Agency (IAEA) is the safety authority that is charged with restricting uranium, plutonium and technological capacity for use in weapons and monitoring the NPT. However, the effectiveness of this institution has been questioned since it does not have the authorization to inspect the facilities of non-NPT members nor can it inspect any NPT member facility of its choosing and there is currently only a partial accounting tracking system of materials (MIT, 2003). In light of current proliferation developments regarding India, Iran and North Korea, such doubt seems warranted.

Obviously, the costs of nuclear proliferation can be extremely significant. However, the damages and the probabilities of risk are highly uncertain, which preclude this external burden from being quantified. Moreover, trying to assess the marginal costs on a site and receptor specific basis is seemingly impossible, so any valuation would have to be for average values rather than marginal ones.

[214] In addition, Canada is also a member of the Comprehensive Nuclear Test Ban Treaty (IAEA, 2003).

5.3.4 Other potentially non-negligible incomputable costs that apply to all generation alternatives under study

Several other potentially significant external burdens that are common to each generation alternative are not evaluated in this assessment. Employment impacts and fiscal subsidies, although potentially non-negligible, are not considered to be external costs.

Accounting for changes in employment is controversial with respect to whether or not such effects ought to be considered externalities. Certainly, the expansion of each particular generation alternative affects the number of employment gains (or losses) and can be viewed as external in the sense that they are not included in the price of electricity that consumers pay.[215] Chernick et al. (1993, volume 3, p. 40) state that:

> Estimating the value to society of jobs gained and lost entails more layers of complexity and judgement including determining whether one job class is more or less valuable than another, given the quality of the work and the opportunities it offers to the unemployed, to workers that are currently under-utilized, and to highly skilled workers; and regional factors, including the mix of available job skills and the local economy.

Although various electricity externality studies have included such effects in the past, it appears that excluding employment-related impacts from consideration as an externality has become the prevailing norm (Sundqvist, 2002). According to Sundqvist (2002), this is reasonable as long as liquidity in the labour market exists, which is assumed to be valid for the purpose of this assessment. It is noted, however, that employment effects may yet be an important criterion in capacity planning decisions, but they are not within the scope of this assessment.

Finally, direct and indirect financial subsidies are not incorporated into this analysis either. According to Myers and Kent (2001, p. 5):

> [A] subsidy is a form of government support extended to an economic sector (or institution, business or individual), generally with the aim of promoting an activity that the government considers beneficial to the economy overall and to

[215] This change in employment refers to the direct impacts of jobs gained or lost. Secondary effects (i.e. a change in the price of electricity due to the increase in a particular generation alternative that raises or lowers the cost of production throughout the economy, which in turn raises or lowers employment levels), are thought to be negligible relative to direct effects on local employment (EC, 2005).

> society at large…A subsidy can be supplied in the form of a monetary payment or other transfer or through relief of an opportunity cost.

Subsidies may take various forms including direct subsidies, tax credits, preferential tax rates, interest free loans, favourable regulatory frameworks, insurance premium reductions, investments in research and development and government induced fuel supply security.

There is some anecdotal evidence on energy-related subsidies in Canada. For instance, the federal government provides Atomic Energy of Canada Limited with $100 million in R&D support on an annual basis, which is a significant subsidy to the nuclear industry (IAEA, 2003). In addition, according to, Taylor et al. (2005), the Government of Canada provided subsidies to the oil and gas sector in 2002 in the amount of $1.4 billion via direct spending (e.g. R&D spending), government program budgetary expenses and revenue collection (e.g. tax breaks and royalty collections) (figures are in 2000 CDN$). Furthermore, the IEA (2004) asserts that annual government-funded R&D expenditure for renewable electricity generation sources in Canada was approximately half that of oil & gas and nuclear, respectively, in 2003.

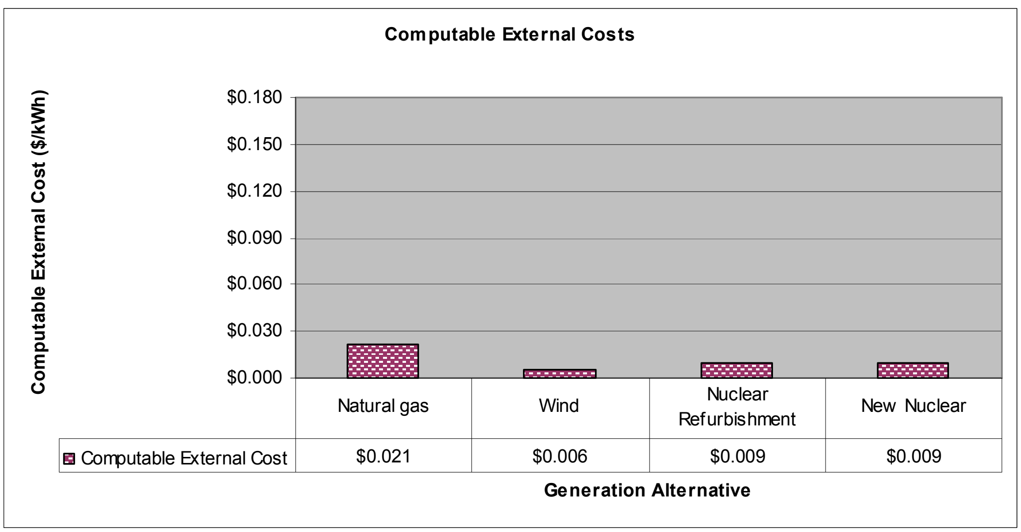
Owen (2006) notes that subsidies distort resource allocations in a similar fashion as external costs yet they should not technically be considered externalities. Moreover, a comprehensive assessment of subsidies for each generation alternative under study is not available, partially since the estimation of some subsidies remains "subjective" (Kammen and Pacca, 2004, p. 318). In undertaking a partial assessment of perverse subsidies, Myers and Kent (2001) also comment on the difficulties associated with identifying and quantifying subsidies. According to Friedrich and Voss (1993, p. 118), "it is quite difficult to allocate expenditure for research and development to individual plants".

However, it is clear that fossil fuel and nuclear generation have historically received the majority of electricity sector subsidies worldwide (Myers and Kent, 2001). It is recognized that while considerable past subsidies to conventional generation alternatives such as natural gas and nuclear have contributed to their development, such previous investments would not factor into the calculation of marginal costs of expanding electricity generation capacity, since only current subsidies would have an impact on marginal costs. In any event, due to the lack of consistent data, subsidies are not considered in the analysis at this time. However, more research on this issue would be beneficial.

5.3.5 Computable external cost summary

Figure 5-29 illustrates the computable external burden estimates for each generation alternative. Wind has the lowest computable external costs per kWh followed by the nuclear generation alternatives.

Figure 5-29: Computable external cost summary ($/kWh)



A summary of the breakdown of individual computable external cost elements for each generation alternative is shown in Figure 5-30. The generation alternatives are ranked in terms of lowest computable external costs and the alternative with the lowest computable external cost is highlighted in bold.

Figure 5-30: Summary of computable external cost elements for each generation alternative ($/kWh)

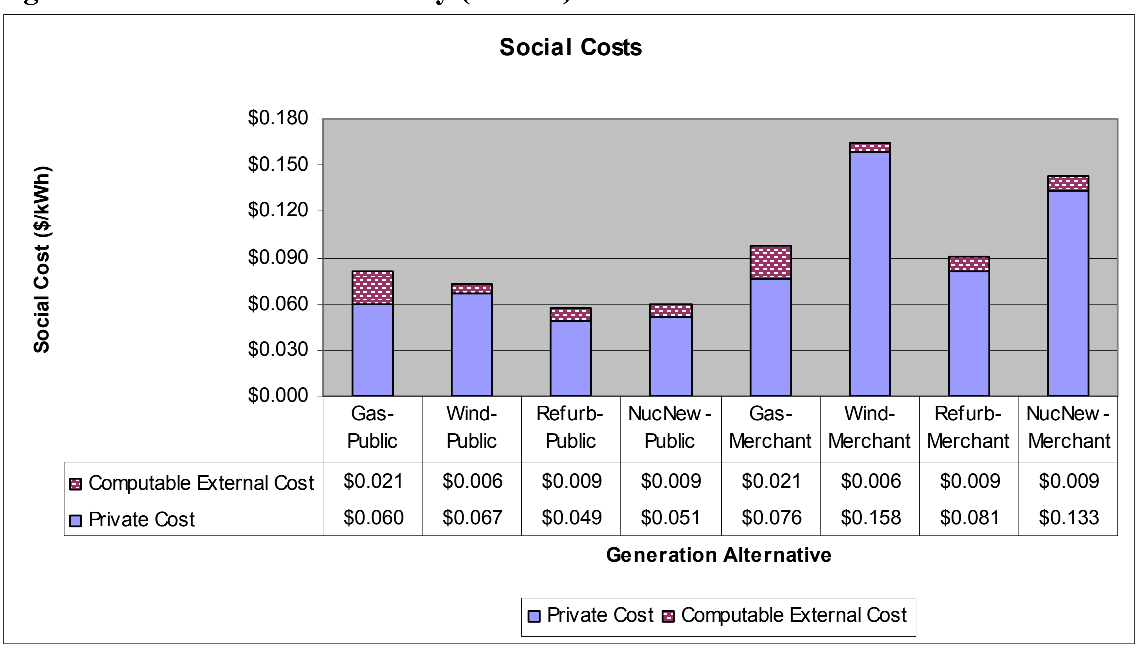
Computable external costs	Natural gas	Wind	Nuclear Refurbishment	New Nuclear
Climate change	0.005	0.000	n/a	n/a
Premature mortality from air pollution	0.016	0.002	n/a	n/a
Miscellaneous	n/a	0.003	n/a	n/a
Accidents	n/a	n/a	0.002	0.002
Health costs from radioactivity	n/a	n/a	0.007	0.007
Total computable external costs	0.021 (4)	**0.006 (1)**	0.009 (2)	0.009 (2)

In the next step, private costs and computable external costs are used to determine social costs for each generation alternative.

5.4 *Step 4: Social cost assessment results and data analysis*

In this step of the methodological framework, the social costs derived in the previous sections are aggregated. Figure 5-31 depicts the private costs and the computable external costs for each generation alternative in each perspective.

Figure 5-31: Social cost summary ($/kWh)



	Gas-Public	Wind-Public	Refurb-Public	NucNew - Public	Gas-Merchant	Wind-Merchant	Refurb-Merchant	NucNew - Merchant
Computable External Cost	$0.021	$0.006	$0.009	$0.009	$0.021	$0.006	$0.009	$0.009
Private Cost	$0.060	$0.067	$0.049	$0.051	$0.076	$0.158	$0.081	$0.133

5.4.1 Natural gas

Social costs associated with natural gas are \$0.081/kWh in the public scenario and \$0.097/kWh in the merchant scenario.

5.4.2 Wind

Social costs associated with wind are \$0.073/kWh in the public scenario and \$0.164/kWh in the merchant scenario.

5.4.3 Nuclear

Social costs associated with nuclear refurbishment are \$0.058/kWh in the public scenario and \$0.090/kWh in the merchant scenario. When new nuclear generation is evaluated in the public scenario, social costs are \$0.060/kWh and alternatively, social costs of new nuclear generation are \$0.142/kWh when the merchant perspective is applied.

5.4.4 Social cost summary

In both the public and the merchant perspective, nuclear refurbishment has the lowest social costs per kilowatt-hour among the generation alternatives evaluated. A summary of the breakdown of individual social cost elements for each generation alternative is shown in Figures 5-32 and 5-33. The generation alternatives are ranked in terms of lowest private and social costs and the alternative with the lowest private and social costs in each scenario is highlighted in bold. Note that numbers may not add precisely due to rounding.

Figure 5-32: Summary of social cost elements for each generation alternative ($/kWh), public perspective

Public Scenario	Natural gas	Wind	Nuclear Refurbishment	New Nuclear
Private costs				
Capital	0.009	0.047	0.029	0.031
O&M	0.006	0.015	0.014	0.014
Fuel	0.045	n/a	0.003	0.003
Integration & balancing	n/a	0.005	n/a	n/a
Waste & decommissioning	n/a	n/a	0.003	0.003
Income tax	n/a	n/a	n/a	n/a
Private cost subtotal	0.060 (3)	0.067 (4)	**0.049 (1)**	0.051 (2)
Computable external costs				
Climate change	0.005	0.000	n/a	n/a
Premature mortality from air pollution	0.016	0.002	n/a	n/a
Miscellaneous	n/a	0.003	n/a	n/a
Accidents	n/a	n/a	0.002	0.002
Health costs from radioactivity	n/a	n/a	0.007	0.007
Computable external cost subtotal	0.021	0.006	0.009	0.009
Social costs	0.081 (4)	0.073 (3)	**0.058 (1)**	0.060 (2)

Figure 5-33: Summary of social cost elements for each generation alternative ($/kWh), merchant perspective

Merchant Scenario	Natural gas	Wind	Nuclear Refurbishment	New Nuclear
Private costs				
Capital	0.019	0.097	0.046	0.077
O&M	0.005	0.015	0.014	0.014
Fuel	0.045	n/a	0.003	0.003
Integration & balancing	n/a	0.005	n/a	n/a
Waste & decommissioning	n/a	n/a	0.003	0.003
Income tax	0.007	0.041	0.015	0.036
Private cost subtotal	**0.076 (1)**	0.158 (4)	0.081 (2)	0.133 (3)
Computable external costs				
Climate change	0.005	0.000	n/a	n/a
Premature mortality from air pollution	0.016	0.002	n/a	n/a
Accidents	n/a	n/a	0.002	0.002
Health costs from radioactivity	n/a	n/a	0.007	0.007
Miscellaneous	n/a	0.003	n/a	n/a
Computable external cost subtotal	0.021	0.006	0.009	0.009
Social costs	0.097 (2)	0.164 (4)	**0.090 (1)**	0.142 (3)

The perspective from which the private costs are evaluated has a significant effect on the social cost estimates: the more capital intensive the generation alternative, the larger the social cost increase is going from a public to a merchant scenario. In the public scenario, accounting for computable external costs changes the ranking of the wind and natural gas alternatives. However, as will become apparent in the following section, this will not affect the capacity expansion decision based on social costs. In contrast, the ranking of nuclear refurbishment and natural gas in terms of social costs is altered when computable external costs are accounted for in the merchant scenario and this will have an effect on the capacity expansion plan.

5.4.5 Data analysis: Capacity expansion plan based on social cost estimates

Social cost data are used to determine the allocation of installed generation capacity required to meet future electrical supply needs in Ontario at the lowest social costs. The generation alternatives exhibiting the lowest social cost subject to any capacity expansion constraints are selected to fill the 7,000 MW supply gap. Figure 5-34 provides a summary of the marginal unit capacity and capacity expansion constraints associated with each generation alternative, as described in section 4.2.4.1.

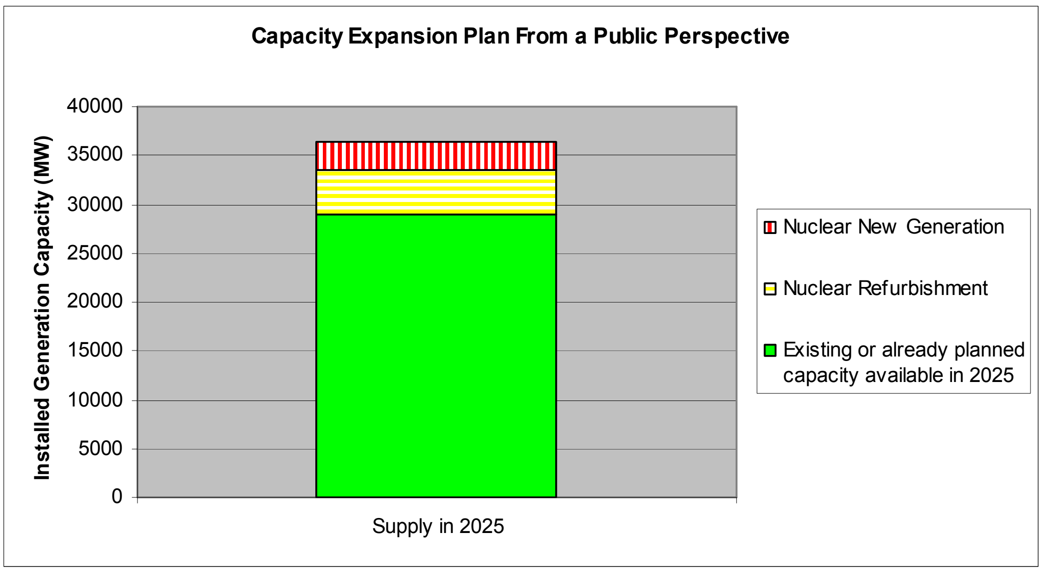
Figure 5-34: Marginal generating unit capacity and capacity expansion constraints

Electricity Generation Alternative	Marginal Unit Capacity (MW/unit)	Capacity Expansion Constraints (Max MW)
Natural gas	500	none
Wind	1.8	3,100
Nuclear refurbishment	752	4,512
New nuclear generation	700	none
Total	n/a	7,000

Given the results of the social cost assessment and the constraints listed in Figure 5-34, the capacity expansion plan for the base case scenario is as follows:

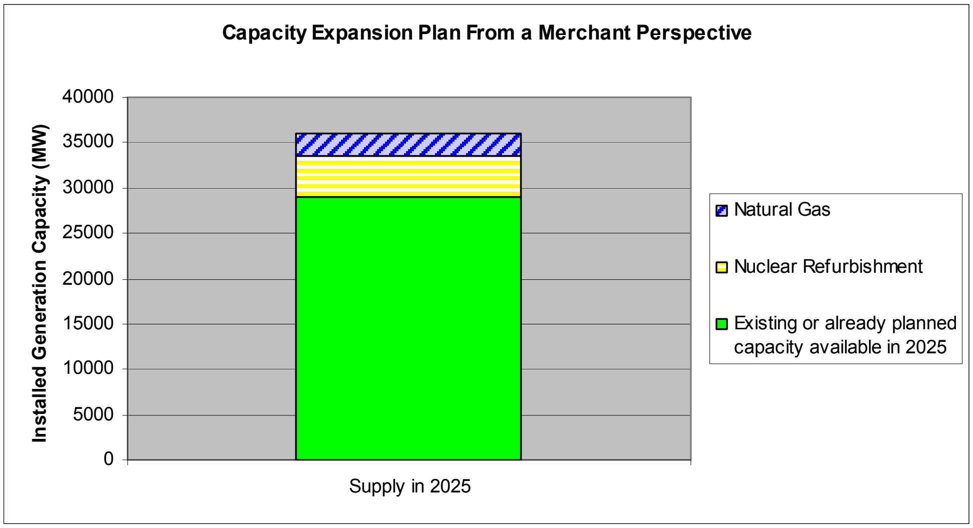
Under the publicscenario, nuclear refurbishment has the lowest social costs and is maximized subject to its 4,512 MW availability. This translates into the refurbishment of all six available “blocks” of 752 MW nuclear reactors (12 reactors, which have been grouped into sets of two). To make up the remainder of the supply gap, the generation alternative with the second lowest social costs, new nuclear generation, is selected. Based on its 700 MW unit capacity, four new nuclear reactors would be required, as illustrated in Figure 5-35.

Figure 5-35: Capacity expansion plan under public perspective



Under the merchant scenario, the results are partially altered, as illustrated in Figure 5-36. Under these circumstances, nuclear refurbishment remains the lowest cost generation alternative in terms of the social costs derived here and again all available nuclear reactors in Ontario should be refurbished. However, in this scenario, the remainder of the supply gap should be filled by natural gas rather than by new nuclear generation. Given that natural gas-fired generation is associated with a 500 MW generating unit capacity, five new natural gas facilities would be required.

Figure 5-36: Capacity expansion plan under merchant perspective



5.5 Step 5: Sensitivity analysis

In step 5 of the methodological framework, a sensitivity analysis is carried out. The purpose is to test a range of values for key parameters and to assess the effect of such changes on the capacity expansion plan derived in the base case. The following variables (where applicable) are evaluated under both public and merchant scenarios: public discount rate, merchant discount rate (when project is financed entirely through equity, as in the base case, and also when debt is included in the capital structure), average capacity factor, operating lifetime, generating unit capital costs, fuel costs, heat rate, greenhouse gas emission permit price, health costs and probability of nuclear accident/risk aversion premium.[216] Each respective variable is increased (decreased) by several amounts up to what is considered to be a reasonable upper (lower) bound relative to the base case

[216] It is noted that the sensitivities tested for the public and merchant discount rate, average capacity factor, operating life, capital costs, fuel costs, and heat rate only measure the effect on private costs. Computable external costs are held constant and are then added to private costs to arrive at social costs for each individual variable for each generation alternative. Conversely, only the effect on the computable external costs are measured by the sensitivities tested for GHG permit price, health costs and accident probability/risk aversion premium. For these variables, private costs are held constant and are added to the computable external costs to arrive at social costs for each individual variable for each generation alternative.

figure.[217] For each parameter tested, base case variables are shown in parentheses and base case social cost estimates are shown for reference. Sensitivities that are able to alter the capacity expansion decision are highlighted in bold and a short description is provided for each variable tested. In addition, a broader discussion of the sensitivity analysis is presented in Chapter Six.

5.5.1 Public discount rate

Figure 5-37: Social cost sensitivity to public discount rate percentage point changes ($/kWh)

	Natural Gas	Wind	Nuclear Refurbishment	Nuclear New Generation
Public				
2 %	0.078	0.058	0.052	**0.049**
3 %	0.079	0.063	0.054	**0.052**
4 %	0.080	0.067	0.056	0.056
Base Case (5%)	0.081	0.073	0.058	0.060
6 %	0.082	0.078	0.060	0.064
7 %	0.083	0.084	0.062	0.069
8 %	0.084	0.090	0.064	0.075
Merchant (unchanged)				
Base Case	0.097	0.164	0.090	0.142

Under the public scenario, the results are unaffected except for when the discount rate is reduced by two or three percentage points for each generation alternative. In such a case, new nuclear generation would be utilized to fill the supply gap in entirety rather than the expansion plan in the base case in which a mixture of refurbishment and new build are utilized.

[217] However, it is possible that in practice some variables will fall outside of the range of sensitivities evaluated here, which could alter the capacity expansion decision. Consequently, the results of this sensitivity analysis are considered to be context specific and should be interpreted carefully.

5.5.2 Merchant discount rate

The sensitivity analysis tests changes to the merchant cost of capital when the capital structure is financed entirely through equity, which is the assumption in the base case scenario, and when debt is introduced into the capital structure of the project.

5.5.2.1 Merchant discount rate for an all-equity project

Figure 5-38: Social cost sensitivity to percentage point changes in the cost of equity for an all-equity project ($/kWh)

	Natural Gas	Wind	Nuclear Refurbishment	Nuclear New Generation
Public (unchanged)				
Base Case	0.081	0.073	0.058	0.060
Merchant				
10 %	0.092	0.132	0.079	0.111
11 %	0.094	0.142	0.083	0.121
12 %	0.095	0.153	0.086	0.131
Base Case (13%)	0.097	0.164	0.090	0.142
14 %	0.099	0.175	0.094	0.154
15 %	0.102	0.187	0.098	0.167
16 %	0.104	0.199	0.102	0.180

Based on the sensitivities tested, a change in the cost of equity when generation alternatives are financed entirely with equity does not alter the capacity expansion decision.

5.5.2.2 Merchant discount rate when debt is utilized

In the all-equity scenario, the sensitivity analysis is straightforward and only the cost of equity needs to be altered. However, when debt is utilized, the discount rate for a merchant firm should reflect the weighted average cost of capital (WACC), as discussed in section 4.2.2. The weighted average cost of capital is specified by the following equation:

WACC = (cost of equity x (1 – debt-to-equity ratio)) + (cost of debt x debt-to-equity ratio x (1- tax rate))

When testing the sensitivities of each WACC component when debt is utilized, one variable is changed and the others are held constant. For example, when changes to the cost of equity are evaluated (when debt is utilized), a 7.5% cost of debt, 50/50 debt-to-equity ratio and a 36% tax rate are held constant.[218] In this particular case, a weighted average cost of capital of 8.9% would be used to discount project costs for each generation alternative.[219]

[218] The cost of debt and debt-to-equity ratio figures are consistent with the data in Ayres et al. (2004) (8% cost of debt and 50/50 D/E ratio), OPA (2005) (7% cost of debt and 50/50 D/E ratio) and Navigant (2005) (7.5% cost of debt and 60/40 D/E ratio).
[219] Calculation: 13(0.5) + 7.5(0.5)(0.64) = 8.9. It is assumed that the debt life corresponds with the operating life of each generation alternative.

5.5.2.2.1 Cost of equity

Figure 5-39: Social cost sensitivity to cost of equity percentage point changes when debt and equity are utilized (7.5% cost of debt, 50/50 debt-to-equity ratio & 36% tax rate) ($/kWh)

	Natural Gas	**Wind**	**Nuclear Refurbishment**	**Nuclear New Generation**
Public (unchanged)				
Base Case	0.081	0.073	0.058	0.060
Merchant				
10 %	0.0869	0.106	0.070	0.0874
11 %	0.088	0.111	0.072	0.092
12 %	0.089	0.116	0.073	0.096
13%	0.090	0.121	0.075	0.100
14 %	0.090	0.126	0.077	0.105
15 %	0.091	0.131	0.079	0.110
16 %	0.092	0.136	0.080	0.115

As in the all-equity scenario, the resource allocation decision is unaffected by the sensitivities tested for the cost of equity from the merchant perspective.

5.5.2.2.2 Cost of debt

Figure 5-40: Social cost sensitivity to cost of debt percentage point changes when debt and equity are utilized (13% cost of equity, 50/50 debt-to-equity ratio & 36% tax rate) ($/kWh)

	Natural Gas	**Wind**	**Nuclear Refurbishment**	**Nuclear New Generation**
Public (unchanged)				
Base Case	0.081	0.073	0.058	0.060
Merchant				
4.5 %	0.088	0.111	0.072	0.092
5.5 %	0.088	0.115	0.073	0.095
6.5 %	0.089	0.118	0.074	0.097
7.5%	0.090	0.121	0.075	0.100
8.5 %	0.090	0.124	0.076	0.103
9.5 %	0.091	0.127	0.077	0.106
10.5 %	0.091	0.130	0.079	0.109

Although the utilization of debt can have a significant effect on the social cost estimates (especially for those generation alternatives that are capital intensive), due to the initial starting points in the base case, none of the sensitivities tested for cost of debt were able to alter the capacity expansion plan.

5.5.2.2.3 Debt-to-equity ratio

Figure 5-41: Social cost sensitivity to D/E ratio changes when debt and equity are utilized (13% cost of equity, 7.5% cost of debt & 36% tax rate) ($/kWh)

	Natural Gas	**Wind**	**Nuclear Refurbishment**	**Nuclear New Generation**
Public (unchanged)				
Base Case	0.081	0.073	0.058	0.060
Merchant				
30/70	0.093	0.138	0.081	0.116
40/60	0.091	0.129	0.078	0.108
50/50	0.090	0.121	0.075	0.100
60/40	0.088	0.113	0.072	0.093
70/30	0.087	0.105	0.070	**0.086**

The more debt that is used, the more attractive alternatives with relatively large capital expenditures such as wind and nuclear become since debt is cheaper than equity. As a result, when the debt-to-equity ratio is increased to 70/30 for all generation options, natural gas is replaced by new nuclear generation as the generation option with the second lowest social costs and consequently it should be used to fill the remainder of the supply gap after nuclear refurbishment.

5.5.3 Average capacity factor

Figure 5-42: Social cost sensitivity to average capacity factor percentage point changes ($/kWh)

	Natural Gas	**Wind**	**Nuclear Refurbishment**	**Nuclear New Generation**
Public	(base: 83%)	(base: 31%)	(base: 81%)	(base: 81%)
-15 %	0.083	0.116	0.064	0.067
-10 %	0.082	0.095	0.062	0.064
-5 %	0.082	0.082	0.060	0.062
Base Case	0.081	0.073	0.058	0.060
+5 %	0.080	0.066	0.056	0.058
+10 %	0.080	0.061	0.054	0.056
+15 %	0.079	0.057	0.053	0.055
Merchant	(base: 83%)	(base: 31%)	(base: 81%)	(base: 81%)
-15 %	**0.103**	0.294	0.104	0.168
-10 %	0.101	0.230	0.099	0.159
-5 %	0.099	0.191	0.094	0.150
Base Case	0.097	0.164	0.090	0.142
+5 %	0.096	0.145	0.086	0.136
+10 %	0.095	0.130	0.083	0.130
+15 %	0.093	0.119	0.080	0.125

In the public scenario, the results stay the same regardless of the average capacity factor tested. In the merchant situation, however, the resource allocation plan is affected when the capacity factor declines by 15% for each generation alternative. In this case, natural gas would be counted on to meet the entire supply gap.

5.5.4 Operating life

Figure 5-43: Social cost sensitivity to generating unit operating life changes ($/kWh)

	Natural Gas[220]	**Wind**	**Nuclear Refurbishment**[221]	**Nuclear New Generation**
Public	(base: 27)	(base: 28)	(base: 26)	(base: 29)
-10 yrs	0.083	0.085	0.071	**0.068**
-5 yrs	0.082	0.077	0.0631	**0.06295**
Base Case	0.081	0.073	0.058	0.060
+5 yrs	0.081	0.069	0.054	0.058
+10 yrs	0.081	0.067	0.052	0.056
Merchant	(base: 27)	(base: 28)	(base: 26)	(base: 29)
-10 yrs	**0.100**	0.177	0.110	0.152
-5 yrs	**0.098**	0.169	0.099	0.146
Base Case	0.097	0.164	0.090	0.142
+5 yrs	0.097	0.162	0.085	0.141
+10 yrs	0.097	0.161	0.082	0.140

From the public perspective, nuclear refurbishment has the lowest social costs except when operating life is shortened by five years or more for each generation alternative. When this occurs, new nuclear generation becomes less expensive than nuclear refurbishment and should be counted on to fill the supply gap alone. From the merchant perspective, the results also change when the operating life is shortened by five years or more, in which case natural gas should be used to fill the entire supply gap.

[220] Fuel cost increases were extended by 1% per year for the natural gas scenarios that tested operating life increases.
[221] For the nuclear refurbishment generation alternative, each generating unit was tested at +/- 5 years for the +/- 10 years scenarios. For the +/- 5 years scenarios, the first generating unit is tested at +/- 3 years and the second unit at +/- 2 years.

5.5.5 Generating unit overnight capital expenditures

Figure 5-44: Social cost sensitivity to generating unit overnight capital costs changes ($/kWh)

	Natural Gas	**Wind**	**Nuclear Refurbishment**	**Nuclear New Generation**
Public	(base: 846)	(base: 1845)	(base: 1922)	(base: 3003)
-50 %	0.077	0.049	0.043	0.044
-20 %	0.079	0.063	0.052	0.054
-10 %	0.080	0.068	0.055	0.057
-5 %	0.080	0.070	0.056	0.058
Base Case	0.081	0.073	0.058	0.060
+5 %	0.081	0.075	0.059	0.061
+10 %	0.082	0.077	0.061	0.063
+20 %	0.082	0.082	0.064	0.066
+50 %	0.085	0.096	0.073	0.076
Merchant	(base: 846)	(base: 1845)	(base: 1922)	(base: 3003)
-50 %	0.086	0.095	0.059	**0.085**
-20 %	0.093	0.136	0.078	0.120
-10 %	0.095	0.150	0.084	0.131
-5 %	0.096	0.157	0.087	0.137
Base Case	0.097	0.164	0.090	0.142
+5 %	0.099	0.171	0.093	0.154
+10 %	0.100	0.178	0.096	0.165
+20 %	**0.1022**	0.192	0.1025	0.192
+50 %	**0.109**	0.233	0.121	0.200

The results are unaffected by changes to overnight capital costs in the public scenario. With respect to the merchant perspective, however, several changes in generating unit overnight capital costs cause the supply gap decision to be modified. If capital costs decrease by 50% for each generation alternative, new nuclear generation becomes the option with the second lowest social costs after nuclear refurbishment. In addition, if capital costs are increased by 20% or more for each generation alternative, natural gas becomes less expensive than nuclear refurbishment and hence, it should be the only generation alternative required to fill the supply gap.[222]

[222] Although it was not included in the sensitivity analysis, altering the capital costs associated with natural gas infrastructure would have a negligible effect on the capacity expansion decision..

5.5.6 Fuel costs

Figure 5-45: Social cost sensitivity to fuel cost changes ($/kWh)[223]

	Natural Gas	**Wind**	**Nuclear Refurbishment[224]**	**Nuclear New Generation[224]**
Public	(base: variable)	(base: n/a)	(base: 0.00276)	(base: 0.00276)
-50 %	**0.0583**	n/a	0.056	0.0585
-20 %	0.072	n/a	0.057	0.059
-10 %	0.076	n/a	0.057	0.060
-5 %	0.079	n/a	0.058	0.060
Base Case	0.081	0.073	0.058	0.060
+5 %	0.083	n/a	0.058	0.060
+10 %	0.085	n/a	0.058	0.060
+20 %	0.090	n/a	0.058	0.060
+50 %	0.103	n/a	0.059	0.061
Merchant	(base: variable)	(base: n/a)	(base: 0.00276)	(base: 0.00276)
-50 %	**0.075**	n/a	0.089	0.141
-20 %	**0.088**	n/a	0.090	0.142
-10 %	0.093	n/a	0.090	0.142
-5 %	0.095	n/a	0.090	0.142
Base Case	0.097	0.164	0.090	0.142
+5 %	0.100	n/a	0.090	0.143
+10 %	0.102	n/a	0.090	0.143
+20 %	0.107	n/a	0.091	0.143
+50 %	0.120	n/a	0.091	0.144

The results remain constant from the public perspective except for the situation where fuel costs decrease by 50% for each generation alternative. Under such a scenario, natural gas should be utilized to fill the remainder of the supply gap after nuclear refurbishment

[223] Net fuel costs (including delivery) are evaluated.
[224] For nuclear scenarios under evaluation, the combined decommissioning and waste management costs are approximately equal to nuclear fuel costs in the base case. Consequently, performing a sensitivity analysis for these variables would look very similar to the sensitivity analysis for nuclear fuel costs.

since it becomes less expensive than new nuclear generation, albeit by a very narrow margin. In the merchant scenario, nuclear refurbishment remains the least expensive alternative as fuel costs increase. However, if fuel costs decline by 20% or more for each generation alternative, natural gas becomes the least cost option and should be used to fill the entire supply gap.

5.5.7 Heat rate

Figure 5-46: Social cost sensitivity to heat rate changes ($/kWh)

	Natural Gas	**Wind**	**Nuclear Refurbishment**	**Nuclear New Generation**
Public	(base: 0.006967)	(base: n/a)	(base: n/a)	(base: n/a)
0.006500 Mcf/kWh	0.078	n/a	n/a	n/a
Base Case	0.081	0.073	0.058	0.060
0.007500 Mcf/kWh	0.084	n/a	n/a	n/a
Merchant	(base: 0.006967)	(base: n/a)	(base: n/a)	(base: n/a)
0.006500 Mcf/kWh	0.094	n/a	n/a	n/a
Base Case	0.097	0.164	0.090	0.142
0.007500 Mcf/kWh	0.101	n/a	n/a	n/a

Natural gas fuel costs are a function of the heat rate (as the heat rate escalates, more fuel is needed to generate each kWh of electricity), so only the natural gas-fired generation alternative is tested for this variable. The capacity expansion decision is unaffected by the heat rate sensitivities tested, regardless of the perspective.

5.5.8 Greenhouse gas permit price

Figure 5-47: Social cost sensitivity to GHG permit price changes ($/kWh)

	Natural Gas	**Wind**	**Nuclear Refurbishment**	**Nuclear New Generation**
Public	(base: $15/t)	(base: $15/t)	(base: n/a)	(base: n/a)
$5/t CO_2-eq	0.077	0.072	n/a	n/a
$10/t CO_2-eq	0.079	0.072	n/a	n/a
Base Case	0.081	0.073	0.058	0.060
$30/t CO_2-eq	0.086	0.073	n/a	n/a
$60/t CO_2-eq*	0.097	0.073	n/a	n/a
Merchant	(base: $15/t)	(base: $15/t)	(base: n/a)	(base: n/a)
$5/t CO_2-eq	0.094	0.164	n/a	n/a
$10/t CO_2-eq	0.096	0.164	n/a	n/a
Base Case	0.097	0.164	0.090	0.142
$30/t CO_2-eq	0.103	0.164	n/a	n/a
$60/t CO_2-eq*	0.113	0.165	n/a	n/a

* Note: The $60/t CO_2-eq maximum price is based on the maximum price estimated by Tol (2005).

The resource allocation decision is unaffected by the sensitivities tested for the greenhouse gas permit price in each perspective.

5.5.9 Health costs

Figure 5-48: Social cost sensitivity to health cost changes ($/kWh)

	Natural Gas	**Wind**	**Nuclear Refurbishment**	**Nuclear New Generation**
Public	(base: 0.016)	(base: 0.00238)	(base: 0.007)	(base: 0.007)
-50 %	0.073	0.071	0.054	0.056
-20 %	0.078	0.072	0.056	0.059
-10 %	0.079	0.072	0.057	0.059
-5 %	0.080	0.072	0.057	0.060
Base Case	0.081	0.073	0.058	0.060
+5 %	0.082	0.073	0.058	0.060
+10 %	0.082	0.073	0.058	0.061
+20 %	0.084	0.073	0.059	0.061
+50 %	0.089	0.074	0.061	0.063
Merchant	(base: 0.016)	(base: 0.00238)	(base: 0.007)	(base: 0.007)
-50 %	0.089	0.163	0.087	0.139
-20 %	0.094	0.164	0.089	0.141
-10 %	0.096	0.164	0.089	0.142
-5 %	0.097	0.164	0.090	0.142
Base Case	0.097	0.164	0.090	0.142
+5 %	0.098	0.164	0.090	0.143
+10 %	0.099	0.164	0.091	0.143
+20 %	0.101	0.165	0.091	0.144
+50 %	0.105	0.165	0.093	0.146

To evaluate health costs, premature mortality costs associated with air pollution from electricity generation is tested for natural gas, premature mortality costs associated with air pollution from upstream emissions is tested for wind and premature mortality costs, non-fatal cancer costs and hereditary complication costs are tested for the nuclear generation alternatives. The results are unaffected by the health cost sensitivities evaluated here, regardless of whether public or merchant assumptions are evaluated.

5.5.10 Nuclear accident probability or public risk aversion premium

Figure 5-49: Social cost sensitivity to changes in probability of a nuclear accident or changes in public risk aversion premium ($/kWh)

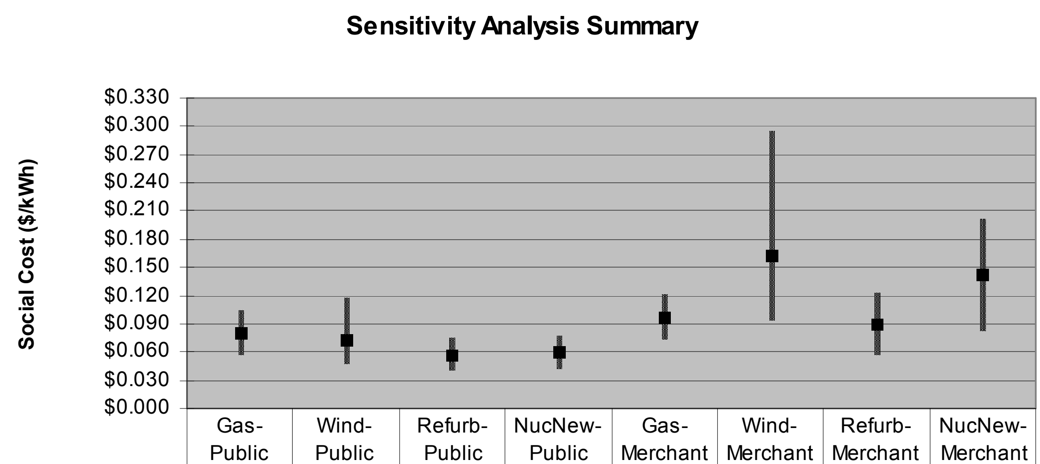
	Natural Gas	**Wind**	**Nuclear Refurbishment**	**Nuclear New Generation**
Public	(base: n/a)	(base: n/a)	(base: 0.002)	(base: 0.002)
-100 %	n/a	n/a	0.055	0.057
-50 %	n/a	n/a	0.057	0.059
-25 %	n/a	n/a	0.057	0.059
Base Case	0.081	0.073	0.058	0.060
+25 %	n/a	n/a	0.058	0.060
+50 %	n/a	n/a	0.059	0.061
+100 %	n/a	n/a	0.060	0.062
Merchant	(base: n/a)	(base: n/a)	(base: 0.002)	(base: 0.002)
-100 %	n/a	n/a	0.088	0.140
-50 %	n/a	n/a	0.089	0.141
-25 %	n/a	n/a	0.089	0.142
Base Case	0.097	0.164	0.090	0.142
+25 %	n/a	n/a	0.091	0.143
+50 %	n/a	n/a	0.091	0.144
+100 %	n/a	n/a	0.092	0.145

Natural gas and wind are held constant since this variable is only applicable to the nuclear alternatives. The results from the public and merchant point of view are unaffected by the changes in the probability of a nuclear accident or in the public risk aversion premium evaluated here.

5.5.11 Sensitivity analysis summary

Figure 5-50 illustrates the range of social cost estimates for each generation alternative based on the variables that were tested in the sensitivity analysis. Each line in the graph represents the range of social costs estimates for each generation alternative and base case social cost estimates are denoted by the square on each line.

Figure 5-50: Sensitivity analysis summary



	Gas-Public	Wind-Public	Refurb-Public	NucNew-Public	Gas-Merchant	Wind-Merchant	Refurb-Merchant	NucNew-Merchant
Upper Range	$0.103	$0.116	$0.073	$0.076	$0.120	$0.294	$0.121	$0.200
Lower Range	$0.058	$0.049	$0.043	$0.044	$0.075	$0.095	$0.059	$0.085
Base Case	$0.081	$0.073	$0.058	$0.060	$0.097	$0.164	$0.090	$0.142

Generation Alternatives

The sensitivity analysis can mitigate some of the uncertainty associated with the results obtained for the base case. However, it is noted that this kind of analysis is limited in that it only tests one variable at a time, rather than evaluating the effects on the results when two or more variables are evaluated simultaneously. Obtaining these kinds of data may provide a better understanding of the results, especially if some of the sensitivity variables are correlated. However, this level of analysis did not fall within the scope of this assessment, as there are a multitude of combinations that could potentially be assessed. Yet, without actually testing more than one variable at a time, it is hypothesized that various scenarios could be derived in which the capacity expansion plan would be altered. Similarly, it is believed that numerous scenarios resulting in an altered resource allocation plan would exist if a particular variable was changed for only one generation alternative (while holding the others constant), as opposed to the method utilized here in which changes to each variable are applied to every generation option uniformly.

5.6 Chapter summary

In this chapter, private and external costs were derived and aggregated to arrive at social cost estimates for each generation alternative. Such estimates were used to determine how installed electricity generation capacity should be expanded to meet the forecasted Ontario supply gap in 2025 if the decision were based solely on the results of this assessment. In addition, the base case results were tested in a sensitivity analysis to determine the effects on the results when key variables were changed. Each sensitivity variable was discussed briefly in terms of its ability to affect the capacity expansion decision. However, a broader discussion of the results of the sensitivity analysis is presented along with the main findings from the base case in Chapter Six.

Chapter 6 Discussion of the findings

6.1 Introduction

In the previous chapter, social cost estimates were derived for each generation alternative and these estimates were used to determine a capacity expansion plan that meets the forecasted supply gap at the lowest social costs. Private costs were assessed under public and merchant scenarios and computable external costs were then added to the private costs of each generation alternative to arrive at social costs for each set of evaluation assumptions. Subsequently, a sensitivity analysis was carried out to evaluate the effect on the base case capacity expansion decision when key variables were altered. The purpose of this chapter is to elaborate on the findings of Chapter Five, distilling the key issues affecting the results of the evaluation. In addition, the notable limitations of the research and how such limitations may influence the resource allocation decision are identified and the main implications of the social cost assessment are considered. This discussion begins with an analysis of private costs, followed by external costs and social costs.

6.2 Private costs

Since there is a lack of consensus regarding the appropriate private costs and planning assumptions for each generation alterative, the average for each private cost factor and planning assumption was taken from the relevant literature so that the cost estimates derived in this analysis could reflect more than one particular viewpoint. However, for some variables (e.g. nuclear waste management), only a few data sources were available to evaluate and hence the paucity of the data may have hindered the desired effect that otherwise would have been obtained. Moreover, it is acknowledged that if the secondary data incorporated into this assessment were erroneous or unreliable, then the results derived here would be correspondingly skewed. However, utilizing the secondary data could be viewed as favourable since it relies upon the diversity of the data in the literature rather than on one “superior” set of assumptions, which likely does not exist.

As can be expected, the proportion of capital expenditures, operations and maintenance costsand fuel costs that comprise the private cost structure of each generation alternative differs among generation alternatives and also between evaluation perspectives. Whereas natural gas-fired generation is heavily weighted by fuel costs, wind and nuclear generation options exhibit a larger proportion of generating unit capital costs. The relationship between the private cost structure and the evaluation perspective produced a different set of private costs (and thus social costs) for each generation alternative, resulting in a different capacity expansion plan to meet forecasted demand requirements depending on the perspective employed.

6.2.1 Public perspective

Under the publicset of assumptions, nuclear refurbishment has the lowest private costs and overall social costs. However, due to capacity constraints, it can only partially contribute to the forecasted 7,000 MW supply gap. Therefore, the second least expensive generation alternative – new nuclear generation – should be counted on to fill the balance of the capacity expansion plan. According to the sensitivity analysis, this result remains constant regardless of which variables are tested except for three cases.[225] This is not to say that the generation alternatives are insensitive to changes in key variables. For example, wind costs are highly sensitive to the average capacity factor assumed (increasing to \$0.116/kWh and decreasing to \$0.057/kWh when capacity factor is changed by 15% in each direction of the base case). However, given the initial starting points of the nuclear refurbishment and new nuclear generation alternatives, the capacity expansion plan derived in the base case was mostly unaffected by the changes tested in the sensitivity analysis. Consequently, from a public perspective, the social cost estimates associated with natural gas or wind power could not be sufficiently lowered such that the capacity expansion decision in the base case should be altered (i.e. the nuclear

[225] In the public scenario, the capacity expansion decision is altered when the discount rate is decreased by two percentage points or more for all generation alternatives (in which case new nuclear generation should be utilized to fill the complete supply gap), when the operating lifetime of each generating unit is shortened by five years or more for all generation alternatives (in which case new nuclear generation would be counted on to fill the complete supply gap) and when fuel costs are decreased by 50 percent for all generation alternatives (in which case natural gas should fill the remainder of the supply gap after nuclear refurbishment).

alternatives could not be "caught" under any of the sensitivities evaluated here, except for the few cases noted above).

6.2.2 Merchant perspective

When the merchant perspective was considered, natural gas had the lowest private costs. However, when computable external costs were added, natural gas became more expensive than nuclear refurbishment in terms of social costs. Therefore, based on the social cost assessment, nuclear refurbishment should be used to fill the supply gap until its technical capacity is reached and natural gas should be used to fill the remainder of the capacity expansion plan.

Given the results of the social cost assessment, it is clear that the perspective from which private costs are assessed has a considerable effect on the capacity expansion decision. Private costs derived for each respective generation alternative were (in some cases rather significantly) higher when evaluated from a merchant perspective. This is attributed to the higher discount rate, and the tax ramifications associated with merchant projects. However, it is not just the presence of these factors that caused the private costs to increase but also how such factors were related to the private cost structure of each generation alternative that had an effect on the estimates. It is evident that electricity generation options that were more capital intensive were more sensitive to the shift from public to private assumptions, resulting in relatively higher LUECs than that of non-capital intensive generation alternatives. Thus, nuclear and wind generation options, which are the most capital intensive alternatives under evaluation, experienced the highest LUEC increases going from a public to a merchant perspective.

The rate that was used to discount cash flows scheduled to occur in the future had a significant impact on the private cost estimates, with a higher discount rate resulting in larger LUECs for each generation alternative. Since the LUEC is the constant price per kWh that needs to be charged over the operating life of a generating unit (such that the net present value (NPV) of the private cost cash flows is equal to zero), a higher discount rate has the effect of reducing the cash flows that occur in future years. Following the definition of the LUEC, annual cash flows are used to recover the initial capital expenditures. Therefore, a higher constant price would need to be charged to recover the up-front capital costs since the NPV remains equal to zero even as the discount rate rises, causing the LUEC to increase. As a result, an increased discount rate more adversely affects generation alternatives that have larger up-front capital expenditures such as wind and new nuclear since the reduced future cash flows require an even higher price to be charged to recover the capital costs. In contrast, natural gas, which exhibits low capital costs and higher variable (fuel) costs, was not as adversely affected as the other generation alternatives in the merchant scenario, which is why it was more competitive under such assumptions.

Privately financed projects exhibit a higher discount rate than public projects due to the inherent risk associated with each ownership structure. This stems from the fact that the risk associated with public projects are underwritten by the government (i.e. they are assumed by the taxpayers), whereas investors in merchant projects require a higher rate of return for the use of their capital (Ayres et al., 2004). The cost of capital is higher from the merchant perspective whether projects are financed entirely through equity (as in the base case) or partially by debt (as in various scenarios tested in the sensitivity analysis). When debt is utilized the discount rate reflects the weighted average cost of capital. Since debt is cheaper than equity, this has the effect of lowering the LUECs relative to the all-equity scenario, but the estimate for each generation alternative is still larger than corresponding private cost estimates from a public perspective. In general, the larger the debt-to-equity ratio, the lower the weighted average cost of capital and thus the lower the private cost estimates became in the sensitivity analysis (especially for capital intensive generation alternatives). However, even when debt was utilized, only one scenario in the sensitivity analysis was able to affect the capacity expansion decision (when the debt-to-equity ratio was 70/30).

Income taxes also have the effect of raising the LUEC, but this consequence is dampened somewhat by the treatment of depreciation on capital assets (Ayres et al., 2004).

Nevertheless, the annual income tax cost is higher for capital intensive generation alternatives like wind and new nuclear generation since the annual taxable net income needs to be larger to recover the larger up-front costs.

In the merchant scenario, the sensitivity analysis revealed that the capacity expansion plan was less durable than the plan established for the public scenario. There were six cases tested that resulted in an altered resource allocation plan relative to the base case.[226] It is also notable that some of the cases that had the ability to alter the base case results did not seem to be that implausible (e.g. when generating unit capital expenditures increase by 20% for each generation alternative).

It is also noted that in the sensitivity analysis, two variables affected the capacity expansion decision under both perspectives: when fuel costs decrease by 50% and when the generating unit operating life is shortened by five years or more. Although the fuel cost scenario is likely to be an extreme case, it does reflect the sensitivity of the natural gas alternative to changes in fuel costs. On the other hand, a reduction in the duration of a generating unit's operating life by five years or more appears to be a more likely possibility. This variable can be influential because, in general, the less time there is to generate annual cash flows, the higher the price per kWh needs to be in order to recover the up-front capital costs. However, it is noted that private cost estimates are more sensitive to decreases in operating life than to corresponding increases since discounting causes cash flows incurred more than 10 to 15 years in the future to become worth relatively little.

[226] In the merchant scenario, the capacity expansion decision is altered when the debt-to-equity ratio is 70/30 for all generation alternatives (in which case new nuclear generation should be utilized to fill the complete supply gap), when the average capacity factor is decreased by 15% for all generation alternatives (in which case natural gas-fired generation should be used to fill the supply gap in entirety) and when the operating lifetime of each generating unit is shortened by five years or more for all generation alternatives (in which case natural gas should be counted on to fill the complete supply gap). It is also altered when generating unit capital expenditures are increased by 20% or more (in which case natural gas would be utilized to fill the supply gap) or decreased by 50% or more for each generation alternative (in which case new nuclear generation should be used) and when fuel costs are decreased by 20% or more for all generation alternatives (in which case natural gas should be used to fill the entire supply gap).

6.2.3 Which evaluation perspective is appropriate for this assessment?

Since there is a large discrepancy between the private costs derived under the two perspectives it is of central concern to determine which perspective is more suitable for this assessment of Ontario electricity generation alternatives. Evaluating electricity generation projects from a public standpoint measures the costs without considering merchant financing or taxation. According to Ayres et al. (2004, p. 1-2), the public perspective can be considered a "pure economic assessment" that does not consider "transfer payments [that are] not essential to the project itself". However, since the assessment of social costs carried out here is applied to an actual capacity expansion decision for the Ontario electricity system, it is assumed that realistic financing assumptions should be applied. Before the electricity market restructuring in Ontario occurred, the government-owned monopoly, Ontario Hydro, controlled the market and could invest in publicly financed projects as it saw fit. Today, Ontario Hydro is broken up into several entities and there are a number of electricity producers that compete in the market. While the market is still undergoing changes, some key elements of competition are present.[227] New supply alternatives are brought to market bya competitive bidding process involving independent power producers, which results in long-term supply contracts with the Ontario Power Authority. Therefore, new generation alternatives that are added to the supply mix are required to procure private financing, but some provisions in the OPA supply contracts may reduce some of the investment risk and thus the cost of capital (Thomas, 2004).[228]

Thus, while it appears that a public perspective should not be used to evaluate the private costs of generation alternatives for the purpose of this assessment, a purely merchant perspective may be inappropriate as well. However, it is unclear how the merchant scenario should be altered to reflect the current state of the Ontario electricity market.

[227] However, Ontario Power Generation currently remains the dominant market participant and various restrictions on the rate of return for some of its generating assets prevent a truly competitive environment from developing (OPG, 2006a).

[228] For instance, the OPA pays producers the difference when the market return is below the contracted price (Navigant, 2005). But there is still risk in terms of the producer costs associated with potential time delays, cost overruns and poor performance, which is why a risk premium still exists between public and merchant projects.

Since altering the financing assumptions to reflect a hybrid perspective that accounts for some public and merchant assumptions would be arbitrary without conducting further analysis, the base case results are held constant and it is assumed that the merchant perspective more closely resembles the current operating environment in the Ontario system. It is noted that future research in this area would be beneficial and the role of public private partnerships, in which risk is shared between institutions, may be an opportunity to consider in this regard (Ayres et al., 2004).[229]

It appears that without altering the financial assumptions in the merchant scenario, wind and new nuclear generation would have a hard time competing with nuclear refurbishment and natural gas without some form of subsidy. As a point of comparison, it is noted that successful "Request for Proposal" natural gas suppliers in Ontario in 2005 were accepted at a private cost of between \$0.078/kWh to \$0.080/kWh, which is consistent with the \$0.076/kWh private cost derived in the merchant scenario of this analysis (NEB, 2006). Similar figures for wind power are harder to obtain, however, NEB (2006) notes that generic wind costs are between \$0.050/kWh to \$0.100/kWh and the OPA (2005) estimates that such costs are \$0.102/kWh (2005 CDN\$). It is unclear how some of the assumptions in these studies differ from the underlying assumptions of this analysis, since the private costs derived here for wind under the merchant scenario were \$0.158/kWh. In addition, the \$0.052/kWh (2004 CDN\$) cost associated with the Pickering A unit 1 refurbishment project calculated by CIBC (2004) is similar to the private cost derived from the public perspective in this assessment, rather than the merchant figure of \$0.081/kWh estimated here. The OPA (2005) estimates the cost of a new nuclear reactor to be \$0.079/kWh. However, since this cost has been estimated as high as \$0.209/kWh in the literature (OCAA, 2006), the merchant private cost estimate of \$0.133/kWh obtained in this thesis does not seem too inconsistent and should be seen as indicative of the sensitivity of new nuclear generation to underlying cost assumptions.

[229] "Under such an arrangement public financing could be used for construction of a merchant plant that would then be leased over a long period to private operators. A number of other public/private partnership arrangements are also possible" (Ayres et al., 2004, p. 7).

6.2.4 Limitations of private cost assessment

The evaluation of private costs is associated with various limitations. There is difficulty with predicting variable costs such as fuel costs over the planning horizon. Moreover, certain costs that are expected to be incurred in the very long term (i.e. well after the operating life of the generating unit ceases), such as nuclear waste management costs, are believed to be particularly problematical to evaluate (Thomas, 2005).[230]

Another limitation that exists is due to the different operating lifetimes of the generation alternatives under assessment. For natural gas, wind and new nuclear generation the difference in operating lifetime (27, 28 and 29 years, respectively) appears to be of little consequence. However, the operating lifetime of a refurbished nuclear generating unit is estimated to be significantly lower at a total of 13 years. Interpreting the results when one generation alternative has a significantly higher or lower operating life is challenging because the actual cost that should be used to compare such an alternative to the others would depend on whatever additional generation option is used as a replacement. For example, it would be necessary to determine the cost of replacement generation once refurbished nuclear units go offline at the end of 13 years. For this reason, it was assumed that nuclear refurbishments would be scheduled back to back in "blocks" of two, so that their combined operating life was 26 years (i.e. the first unit would go offline at the end of year 13 and the second unit would come online at the beginning of year 14).[231] To the extent that this does occur in reality, this approach seems to provide a means by which all the generation alternatives can be compared in a seamless fashion. However, if the 12 refurbishments are not carried out back to back, other potentially more costly generation alternatives could be required at the end of 13 years when the operating life of the refurbished units are taken offline and this would distort the results obtained here.

[230] It is noted that any cost overruns that are not realized until some point in the long term future would not be reflected in the results of this assessment but would result in a significant cost to future generations.

[231] Inherent in this assumption is that the second generating unit would be sitting idle from the point when it is deactivated until it begins construction in year 12 to be ready for year 14. Since current nuclear generating units available for refurbishment are scheduled to go offline at different times between 2006 and 2025, this may not be a significant limitation. However, technological advances that may develop over this time, which could alter the relative attractiveness of refurbishing the second unit, are unaccounted for in the analysis.

Furthermore, the LUEC analysis cannot account for delays in the activation of generating units as a result of regulatory requirements, public acceptability concerns, potential construction time overruns and so on. This seems to favour the nuclear generation options which have more stringent regulatory requirements than the other generation alternatives, have been met with considerable public resistance in the past and which have historically been affected by construction time overruns. Wind-powered generation, which may encounter “not in my back yard”-induced public acceptability concerns, is also made more attractive as a result of this limitation, but, it is believed, to a lesser extent than nuclear generation.

In addition, in reality, the amount of electricity produced each year will fluctuate for each generating unit, rather than remain constant as a function of the average capacity factor, which was assumed in the evaluation. The LUEC analysis, which determines the constant price that must be charged for each generating unit to recover the private costs over its lifetime, is affected by the average capacity factor over the lifetime of the unit since the more a generating unit produces electricity, the more revenue it can earn to recover the costs. Therefore, the LUEC results may be affected if a particular generating unit is unavailable for longer periods either at the beginning or end of its operating life (even though the average capacity factor remains constant). The LUEC associated with a generating unit that is unavailable for a greater proportion of time shortly after initial construction would be higher due to the effects of discounting.

The LUEC analysis also cannot account for the benefits of scalability. For example, if a nuclear generating unit, which has the largest generating unit capacity among the generation alternatives assessed, is required to be taken out of service unexpectedly a larger amount of supply is taken offline than if a similar malfunction occurred at a wind turbine or a natural gas generating unit (although the benefit is less pronounced for natural gas than for wind). Similarly, another implication is that modular generation alternatives are more responsive to changes in demand growth, which cannot be reflected in the results of this assessment. For example, if a new nuclear reactor is in the process of being constructed and demand is lower than anticipated, it would be locked in, whereas a more flexible and smaller-scale generation option such as wind or natural gas could more easily be made expendable or scaled back depending on actual demand requirements in the future.

6.3 External costs

Shifting the discussion towards external costs, this assessment determined that computable external costs were largest for natural gas-fired electricity generation, which is generally consistent with external cost estimates derived in the literature. The computable external costs obtained for wind and nuclear generation alternatives were lower than for natural gas, but, in the case of nuclear-fired generation, this is thought to be more likely attributed to the fact that some potentially non-negligible external effects remain incomputable (as discussed in section 5.3.3.5.1).

6.3.1 Limitations of external cost assessment

Despite employing a consistent analytical approach that primarily relies on the state-of-the-art bottom-up damage cost method to evaluate external burdens, the limitations associated with external cost valuation prevent a complete representation of the external costs for each generation alternative under study. There is uncertainty associated with the bottom-up damage cost method in terms of emission dispersion modeling, dose-response functions based on epidemiological data from the literature, the fact that some of the impacts are expected to be incurred over the very long-term, the potential existence of thresholds and cumulative impacts, and various factors associated with the monetary valuation of such impacts (such as the appropriate discount rate, the procedures employed to determine premature mortality costs, and so on). Moreover, there is uncertainty associated with the "second-best" valuation techniques that have been employed in this assessment such as the use of greenhouse gas permit prices to evaluate climate change costs or the evaluation of the public risk aversion to nuclear accidents.

In addition, there are limitations associated with the transfer and adaptation of external costs from secondary data. First, the judgment and potential bias of researchers who derived the original external cost estimates adds to the imprecise character of the computable external cost estimates included in this assessment. Second, the use of secondary data prevents some of the costs from being adapted beyond simply accounting for inflation and currency exchange. Most notably, the external cost estimates incorporated into this assessment rely on different social cost discount rates. For example, the premature mortality costs associated with natural gas-fired emissions are evaluated using a 5% discount rate, the premature mortality costs associated with wind turbine construction utilize a 3% discount rate and the health effects linked to radioactive emissions from the nuclear fuel cycle are assessed at a 0% discount rate so that very long-term impacts are taken into account. Although this is acknowledged as a significant limitation of the assessment methodology used here, the estimates obtained for these external burdens are assumed to be the most appropriate for such burdens found in the literature.

Despite the limitations associated with evaluating external costs, accounting for computable external costs in this assessment was able to alter the capacity expansion decision in the merchant perspective (i.e. it caused nuclear refurbishment to be less expensive than natural gas in the merchant scenario in terms of social costs). However, the sensitivity analysis showed that altering the values obtained for computable external costs would not have a further effect on the capacity planning decision due to the relative magnitude of the starting points of each generation alternative. This raises one of two possibilities: even with refined valuation methods and greater knowledge of external burdens, external cost estimates will not be able to influence the ranking of the generation alternatives further or, what seems to be more likely, it underscores the fact that computing external costs is an exercise that is fraught with various uncertain computable external costs and incomputable external burdens which may actually be significant enough to affect the results in the future.

6.4 Social costs

To reiterate, when the private and external costs were aggregated for each generation alternative in the base case scenario, nuclear refurbishment exhibited the lowest social costs under both public and merchant assumptions. When the public perspective is assumed, new nuclear generation has the second lowest social costs. Conversely, when the merchant scenario is assumed, natural gas has the second lowest social costs. Given that the merchant perspective is considered to be more appropriate for the purpose of this analysis, it appears that, due to their capital intensive nature, the social costs associated with new nuclear generation and wind power are too high to allow such generation alternatives to meet forecasted demand requirements. Based solely on the results of the social costs assessment, a combination of nuclear refurbishment and natural gas should be used to fill the supply gap.

However, given the limitations associated with social cost assessment, the results should be interpreted very carefully. Alnatheer (2006) suggests that quantifying and monetizing the external effects associated with non-fossil fuel based generation alternatives are less developed in the literature, which, according to Owen (2006), appears to provide an advantage to nuclear power since it is associated with several potentially non-negligible external burdens including potential accidents in the waste management stage of the fuel cycle, nuclear weapons proliferation risk and potential terrorism impacts, which remain incomputable. Therefore, basing the capacity expansion decision solely on the results of this thesis, which suggest that nuclear refurbishment should be utilized regardless of the evaluation perspective, may not necessarily be socially optimal. This is supported by the findings of the sensitivity analysis, which showed that a number of changes to key variables were able to result in an altered capacity expansion decision.

6.5 Chapter Summary

This chapter discussed the results obtained for the base case scenario and sensitivity analysis. The main factors that contributed to the estimates and various limitations were outlined. In summary, social cost estimates are only as effective as their underlying methodology and assumptions. Therefore, it is important to be transparent and document how private cost factors, planning assumptions and external costs are derived. The following chapter summarizes the data presented over the first six chapters, draws conclusions and offers some recommendations for future research.

Chapter 7 Conclusion

7.1 Introduction

The first part of this chapter summarizes the main elements of the social cost assessment carried out over the course of the first six chapters. In the second part of this chapter, the main policy implications of the findings are considered and conclusions are drawn about the usefulness of this kind of assessment for evaluating electricity generation alternatives in light of its limitations and strengths. The role that this thesis serves with respect to its contribution to the literature is also briefly re-examined and several recommendations for future research are suggested.

7.2 Thesis summary

Ontario is currently at a pivotal stage in the development of its electricity system and the province faces a significant challenge to ensure that the level of installed generation capacity is sufficient to meet demand requirements over the next two decades. Recent supply mix developments in the Ontario electricity sector, along with the expected decline of some currently installed electricity generation capacity, are forecasted to result in a supply gap of approximately 7,000 MW in 2025.[232] The purpose of the social cost assessment undertaken here was to determine a capacity expansion plan that includes the generation alternative(s) with the lowest social costs, subject to any technical capacity constraints, to fill the supply gap.[233] Four generation alternatives were evaluated: combined-cycle natural gas generation, on-shore wind generation, nuclear generation from the refurbishment of existing Candu reactors and nuclear generation from the construction of new Candu 6 generating units. Such generation alternatives were assumed

[232] This gap is net of already planned capacity expansion and conservation and demand-side management initiatives (OPA, 2005).
[233] It is noted that the shortfall between supply and demand requirements is forecasted to begin as early as 2014. However, the timing regarding when the actual capacity expansion should take place did not fall within the scope of this analysis. Rather, only the supply gap of 7,000 MW in 2025 was considered. In addition, current cost factors and planning assumptions were used (i.e. the base year from which costs and planning assumptions are evaluated was 2006) even though the capacity expansion is forecasted to occur in 2025. It is noted that a re-evaluation of the social costs of each generation alternative closer to 2025 would be beneficial.

to be the most likely grid-connected options to be considered by the Ontario Power Authority in its forthcoming Integrated Power System Plan, which will become the 'roadmap' for the Ontario electricity system over the next two decades.

Social costs are comprised of private and external costs. Private costs include the fuel, operations and maintenance, and capital costs that are necessary to produce electricity. These costs get passed along to consumers through the wholesale market price and are said to be internalized. External costs, on the other hand, are the uncompensated "side-effects" associated with electricity generation that either have an adverse impact on the well-being of individuals in society or at least increase the risk that such impacts will occur, and which are not included in the wholesale price of electricity. Relevant secondary data from the literature were used to estimate the marginal social costs of each generation alternative since marginal values are undistorted by the costs associated with generating units in the existing supply mix.

Private costs were assessed using a LUEC analysis, which determines the constant price that needs to be charged over the operating lifetime of a generating unit such that the sum of the net present value of the annual cash flows over its operating life (including a specified cost of capital) is equal to zero. Only the secondary data sources containing private cost factors and planning assumptions that were applicable to the capacity planning context in Ontario were utilized. Average values from the literature were incorporated into the analysis for each LUEC input variable for each generation alternative under study.

Each generation option was evaluated from a public and a merchant perspective. The assessment of private costs under these scenarios differs in two key respects: the merchant discount rate is higher than the public discount rate and merchant projects are subject to income tax payments.

The discount rate utilized in each perspective reflects time preference, which is the willingness to trade a dollar's worth of consumption at some time in the future for the ability to put it to use today, as well as the risk-adjusted opportunity cost of capital, which is the premium that is required by financiers to invest in a project that, *ceteris paribus*, exhibits increased risk. A public discount rate of 5%, which is used by the Government of Ontario to evaluate long-term projects, was used for the public scenario (Spiro, 2004 cited in DSS for MOE, 2005). It was assumed that this rate is consistent with the cost of long-term public debt, which reflects the rate at which society is willing to trade off current for future consumption. In the base case, the discount rate used to evaluate each generation alternative in the merchant perspective is 13%, which reflects the cost of equity for a project that is financed entirely through equity. The discount rate used in the merchant perspective is higher than the public rate for several reasons. Besides the fact that a private firm has less incentive than the government to delay consumption until some point in the future, the increased discount rate associated with the merchant scenario reflects the increased cost of financing that a private firm assumes by participating in the quasi-competitive Ontario electricity market. Publicly financed projects would have access to cheaper capital than merchant-financed projects due in part to the fact that liabilities are underwritten by the government and because the government is more likely to be better able to diversify risk than a private firm. Consequently, private equity holders (and debt holders where applicable) would require a higher rate of return to offset the increased risk that is associated with a merchant project, which is reflected in the increased discount rate.

Given these parameters, the LUECs were higher for each generation alternative when evaluated from a merchant viewpoint as a result of the more costly financing assumptions and taxes. However, the magnitude that each alternative increased was related to its private cost structure. Capital intensive generation options like wind and new nuclear generation were more sensitive to the shift from public to merchant (i.e. they increased by a significantly larger magnitude), than natural gas-fired generation which exhibited a relatively smaller amount of overnight capital costs. This effect can be attributed to the increased price that would need to be charged over the lifetime of a generating unit in order to recover the up-front capital expenditures since an increased discount rate reduces the value of future cash flows. Consequently, the natural gas LUEC increased by the lowest amount among the generation alternatives assessed going from public to merchant assumptions.

The estimation of external costs, on the other hand, relied on electricity externality studies in the literature that primarily utilized the bottom-up damage cost method since it is believed to be the most effective method in terms of being able to account for site and receptor specificity (Sundqvist, 2004; EC, 2005). This method tracks the dispersion of emissions from their original source and uses dose-response functions derived in the epidemiological literature to estimate the impacts of the dispersed emissions on each affected receptor. Impacts are monetized using valuation techniques that determine the preferences of individuals in society towards such impacts. In addition, other "second-best" approaches were also relied upon for the quantification of some external burdens, where applicable.

A computable external burden assessment was undertaken to determine which external burdens produced over the complete fuel cycle of each generation alternative should be quantified and monetized for the purpose of the social cost assessment. Computability refers to the external burdens that have sufficient data to be evaluated, an adequate ability to be monetized and a magnitude that, once monetized, is large enough such that it is non-negligible relative to the other computable external burdens associated with each respective generation alternative. Since the external burdens that were quantitatively assessed in the literature were considered to have sufficient data availability and monetization ability, the purpose of the computable external burden assessment carried out here was to determine the external burdens that were non-negligible relative to the total external costs for each respective generation alternative. The largest individual burdens, whose sum represented 80% or more, on average, of the total external costs for each generation option were considered non-negligible. Consequently, for natural gas generation, climate change and premature mortality costs associated with natural gas-fired emissions were evaluated. For wind generation, premature mortality associated with wind turbine construction, climate change and miscellaneous costs were evaluated.[234] For nuclear generation, accidents and health impacts associated with radioactive emissions were evaluated. In addition, some potentially non-negligible incomputable burdens were discussed qualitatively for each generation alternative.

Once computable external burdens were identified, the benefit transfer method was used to adapt the most relevant external burdens found in the literature (i.e. those external effects that exhibited the most consistent site and receptor characteristics as the situation under evaluation) to the Ontario electricity generation context for each respective generation alternative.[235] Computable external cost estimates were highest for natural gas. In contrast, computable external costs were lowest for wind and nuclear but in the case of the nuclear-fired generation options it is believed that this outcome may be due to the existence of potentially non-negligible incomputable burdens (EC, 1999b).

Once derived, private and external costs were aggregated to arrive at total social costs for each generation alternative and the social cost results were evaluated in terms of capacity expansion to meet the forecasted supply gap. Under the public perspective, nuclear refurbishment had both the lowest private costs and the lowest social costs. Therefore, based solely on the results of the social cost assessment, nuclear refurbishment should be used to fill the supply gap until its technical capacity constraints are reached and the remainder of the supply gap should be filled by new nuclear generation. Alternatively, when private costs are evaluated from the merchant perspective, natural gas-fired generation had the lowest private costs. However, due to the initial "starting points" of each cost estimate in this scenario, computable external costs had the ability to alter the ranking of the generation alternatives in terms of social costs. Consequently, when computable external costs are accounted for, nuclear refurbishment retains the lowest social costs among the generation alternatives that were evaluated and the remainder of the supply gap should be filled by natural gas-fired generation.

[234] For the wind fuel cycle, miscellaneous external burdens refer to noise disturbance, visual intrusion and land use.
[235] It is noted that external cost estimates were subject to temporal and geographical constraints and avoided double counting.

A sensitivity analysis, which tested the effect on the base case results when one variable was changed and the others were held constant, demonstrated that the evaluation perspective played a significant role in determining the capacity expansion decision.[236] It also showed that the results were sensitive to changes in certain key variables in three situations in the public scenario and six cases in the merchant perspective. Although several of these sensitivities appear to be rather extreme, a few of them are not implausible, which should be seen as indicative of the fact that the assumptions used to assess social costs of electricity generation alternatives have a significant impact on the cost estimates and on the resulting capacity planning decisions.

7.3 Conclusions and future research recommendations

In terms of the market structure governing the Ontario electricity system, a return to the old publicly-run monopoly arrangement seems highly unlikely. Although the electricity market is not a purely competitive environment either, various key elements of competition are present. One may question which market structure actually makes Ontarians better off. However, in this thesis, this matter was not evaluated and the current quasi-competitive market structure was assumed to be an endogenous consideration. Since the social cost assessment was conducted within the context of meeting the forecasted supply gap in Ontario, it was assumed that the merchant perspective is more reflective of the Ontario electricity system and thus the more appropriate perspective from which to evaluate the private costs of each generation alternative.

However, because the electricity market does not resemble a purely competitive environment, the financing assumptions in the merchant scenario, may, potentially, need to be altered. Since it is unclear at this time how such assumptions should be amended, if

[236] The following variables were tested in the sensitivity analysis: discount rate, cost of debt, debt-to-equity ratio, capacity factor, operating life, generating unit overnight capital costs, fuel costs, heat rate, GHG permit price, health costs and probability of nuclear accident/risk aversion premium. It is noted that some variables may, in practice, fall outside of the range of sensitivities evaluated here in which case the results could be affected (i.e. the results may change if actual variables increase or decrease more than the magnitudes tested in the sensitivity analysis).

at all, the base case results have been left unchanged. Although the sensitivity analysis showed that changing the financing assumptions in the merchant scenario had little effect on the capacity planning decision (except when the debt-to-equity ratio was increased significantly), further research on how financing assumptions in the merchant scenario may be revised to better reflect the Ontario electricity market is warranted. In addition, other ways of sharing risk should be explored, including the role of public-private partnerships.

7.3.1 Limitations

It is of considerable note that the results of the social cost assessment undertaken here are context specific and are highly dependent on the methodology and the assumptions used. Departing from the methodology or altering the assumptions in any way may produce different results.[237] Despite the sensitivity analysis that was carried out, various limitations affect the ability to draw definitive conclusions regarding a capacity expansion plan that minimizes social costs.

Private and external cost estimates remain uncertain due to the inherent limitations of social cost assessment. In terms of private costs, various costs are difficult to determine, not least the costs that will be incurred in the long-term such as nuclear waste management obligations. Moreover, limitations associated with LUEC analysis temper the effectiveness of this analysis as well. In addition, the limitations of external cost valuation prevent a complete external cost picture from being realized for each generation alternative. Although the bottom-up damage cost method is believed to be the most effective external cost valuation method, it has only emerged over the last 15 to 20 years and is still a work in progress. As a result, continued research to fill in knowledge gaps and reduce uncertainty is required. In time, as a greater understanding of the actual impacts of computable external burdens become better understood or as incomputable

[237] Therefore, it is noted that the context specific nature of the evaluation may limit the transferability of the results obtained here to other jurisdictions (i.e. the approach can be transferred but not the exact cost data, unless it is appropriate to do so. Those who wish to use the results should take note of the methodology, particular assumptions and context specificity).

burdens potentially become easier to assess, actual computable external costs may fall outside the values tested in the sensitivity analysis and may affect the relative ranking of generation alternatives.

7.3.2 Implications for efficiency and sustainability

In theory, efficiency and sustainability could be attained when social costs are minimized (i.e. when the external costs are fully internalized). In this case, supply capacity could be expanded such that no one could be made better off without making someone else worse off and all environmental, social and economic consequences could be integrated so that current and future generations experienced the lowest possible costs. However, this kind of assessment in general would be incapable of establishing a capacity expansion plan that is definitively efficient and sustainable, since the uncertainty associated with the assessment of social costs precludes one from knowing whether social costs are actually being minimized as a matter of fact (Friedrich and Voss, 1993). Therefore, the best that can be said about employing social cost assessment to determine which generation alternatives to expand supply capacity with is that it can increase the likelihood that obstacles to efficiency and sustainability are overcome if capacity planning decisions attempt to minimize social costs.

Furthermore, even if the capacity expansion plan to meet the supply gap at the lowest social costs were based on social cost estimates that were known to be accurate with certainty, efficiency and sustainability in the electricity system would still probably not be realized. Part of the reason is that capacity expansion only adds marginal generating units to the total supply mix and the heritage generating units in the existing supply mix do not exhibit the lowest social costs (NEB, 2006). Since the wholesale market allocates installed generation alternatives to meet daily demand based on the minimization of private costs, the generation alternatives with the lowest social costs may not be selected at all times.[238] To have a truly efficient and sustainable electricity market that is able to

[238] The market selects from the pool of installed generation alternatives, so the 7,000 MW of marginal capacity added to meet the forecasted supply gap can reduce total social costs, but only through a "trickle-down effect" (i.e. it can internalize some, but not all, of the external costs of electricity generation since the

minimize the social costs of electricity generation, the total supply mix would have to be comprised of generation alternatives that possess the lowest social costs and the market would have to allocate resources in terms of lowest social costs rather than private costs. However, for this to occur, various obstacles to efficiency and sustainability in the electricity system would need to be removed.

Towards this end, integrated energy policies across federal, provincial and local jurisdictions considering interrelationships and synergies of various areas that affect energy utilization are needed since they affect electricity production and consumption in Ontario. For example, since oil sands production is a significant consumer of natural gas it may be prudent to assess whether the large quantities of natural gas that are used in its production could be of greater benefit to society if used to generate electricity instead.[239] In addition, introducing policies that induce consumers to pay the full private cost of electricity (i.e. the price which reflects market conditions) could be beneficial since some consumers are currently "protected" by regulation, which is actually a form of subsidization (NEB, 2006). While, the upcoming shift to time-of-use pricing in Ontario is a favourable development in this regard, various other policies such as the desirability of freezing Ontario Power Generation's return on certain generating units should be re-evaluated.

7.3.3 <u>Strengths</u>

Given the limitations and uncertainty with social cost estimates and the fact that basing decisions on such estimates alone cannot ensure an efficient and sustainable allocation of

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marginal capacity additions can lower the average social costs of the available pool of generation alternatives but not completely minimize them). It is noted that this study is not concerned with evaluating dispatch decisions that minimize social costs, which may be an area to consider for future research.

[239] Other considerations may include, but are not limited to, urban planning and the curbing of urban sprawl, the role of public transportation in the design of transportation systems, the requirement of the R2000 standard in the Building Code, the suitability of a national electricity grid, energy requirements in NAFTA and electricity conservation and demand-side management initiatives. It is noted that the scope of this assessment was confined to the estimation of social costs of selected electricity generation alternatives. However, future research may also consider using social cost assessment to evaluate the effectiveness of some of the policy areas mentioned here as well. For a comprehensive discussion on various initiatives that involve removing barriers to efficiency and sustainability in the electricity sector see Winfield et al. (2004, executive summary).

resources, one may be tempted to discard such an assessment and focus on existing measures to assess electricity generation alternatives. However, to do so would be a mistake. If planners decided to wait for uncertainty to be resolved before undertaking capacity expansion decisions, it is likely that electricity blackouts would become routine. Due to the imperfect and often subjective nature of electricity capacity planning, decisions must often be made without full knowledge and choosing the status quo can have severe consequences. In this light, social cost assessment may in fact be able to assist with capacity expansion decisions due to its ability to assess the trade-offs of electricity generation alternatives.

Current efforts to assess supply mix alternatives involve weighing how such generation alternatives affect reliability, affordability and socio-environmental concerns with respect to the electricity system. At issue is whether existing decision making criteria are able to "balance" these concerns in a way that is able to minimize social costs. Since each generation alternative exhibits a different configuration of private cost factors and planning assumptions and is associated with different external burdens, it is desirable to express all the trade-offs in common units. Consequently, using monetary units to explicitly evaluate social costs can make the relative attractiveness of each generation alternative more apparent.

If one looks beyond the social cost estimates and capacity expansion results derived in this thesis to focus solely on the broader framework itself, it can be observed that this kind of assessment has the ability to add value to capacity planning. Despite its limitations, if carried out in a consistent, transparent and comprehensive fashion, social cost assessment can limit "cherry picking" of diverse trade-offs and enhance the decision making process so that the likelihood that social costs are minimized is increased. Since the input data have a significant impact on the social cost estimates for each generation alternative and do not exhibit a consensus in the literature, this thesis has sought to select values in a way that adheres to these principles (as advocated by EC, 2005). For private cost factors and planning assumptions, average values were taken from the literature for each generation alternative. With respect to the values obtained for computable external burdens, a consistent methodology was implemented to incorporate suitable external cost data that were most reflective of Ontario site and receptor specificity for each generation option. Despite the limitations, an assessment of social costs that adheres to these principles can still provide decision makers with a greater understanding of the complexity involved with deriving such estimates for each generation alternative, even where uncertainty exists for private cost factors, planning assumptions or computable external cost estimates or where external burdens remain incomputable. By contrast, when social costs are derived in a manner that lacks consistency, or comprehensiveness or when it is unclear how estimates have been derived, such an assessment will likely be unable to enhance the decision-making process in an appreciable way.

However, even as social cost assessment is refined in the future, it is likely that cost estimates will never be known with precision. Therefore, capacity expansion will always involve some element of judgement to determine which generation alternatives have the lowest social costs. Consequently, it should be noted that where uncertainty or gaps in knowledge exist, there will always be an opportunity for political influences to encroach upon capacity planning decisions (Burtraw et al., 1995, cited in Rowe et al., 1995). This is indicative of the need for capacity planning to be undertaken in a more transparent fashion at the provincial level and it further reinforces the value of social cost assessment as a tool to curb the “politicization” of capacity expansion policies. It also feeds into current debates regarding the lack of consistency in the terms of long-term supply contracts negotiated with different electricity producers. At the very least, utilizing a social cost assessment would encourage planners to transparently state their assumptions and – whether one agrees with them or not – could identify potentially unjustifiable assumptions, stimulate public debate between different stakeholder groups and potentially shape future decisions so that a broader consensus may be achieved. Where a lack of consensus arises, it may be desirable then to initiate public discourse involving diverse stakeholders, which could take the form of a public inquiry or a wide-ranging environmental assessment.

7.3.4 Implications for the capacity expansion decision

In light of its limitations and strengths, it is noted that social cost assessment should not be used exclusively to evaluate capacity planning alternatives and other policy decisions that affect the electricity system. However, this kind of analysis, if carried out judiciously, should be able to assist policy makers as one instrument in a suite of evaluation tools. Towards this end, the Ontario Power Authority may benefit from such an assessment in compiling its Independent Power System Plan to evaluate meeting electricity generation requirements in Ontario.

This implies that the capacity expansion plan derived here (refer to Figure 5-36), which is based solely on selecting the generation alternatives with the lowest social cost estimates, should not necessarily be viewed as ideal, especially since various limitations of this assessment make nuclear generation appear more attractive. Although nuclear refurbishment had the lowest social costs of any generation alternative from both evaluation perspectives, planners must still consider other relevant information that either does not fall within the scope of a social cost assessment (such as the relatively short expected operating lifetime of the nuclear refurbishment alternative or the lack of scalability), or take into further consideration the areas that are encompassed by social cost assessment but which may not be adequately addressed (for example, long-term waste management costs or incomputable external burdens like nuclear proliferation risk). Moreover, these kinds of considerations should be measured for each generation alternative before capacity expansion is undertaken if a social cost assessment is utilized in the decision making process.

Consequently, it may be prudent for planners to consider adding other generation alternatives such as wind generation to the supply mix (or to at least encourage its development[240]), even though the results of this social cost assessment did not warrant its inclusion under any scenario. This is because wind generation had the lowest computable external costs and it is also widely believed to have the lowest total external costs among

[240] For example, current initiatives such as renewable targets, standard offer contracts and the federal Wind Power Production Incentive subsidy could be strengthened (NEB, 2006).

the alternatives assessed (i.e. even if all the gaps in knowledge could be eliminated). In addition, other factors that have not been included in this analysis may also enter into this consideration.[241] In any event, even though the social costs of wind power currently remain uncompetitive, accounting for computable external burdens at least provides wind generation with a greater capacity to compete with the other generation alternatives under evaluation. According to Friedrich and Voss (1993, p. 122):

> [I]t is not possible to prove that external costs are at least of such an order of magnitude that renewable energy systems which are far from being economic would become economically viable. Consequently, a decision to use such renewable energy systems has still to be the result of the subjective balancing of pros and cons including the consideration of external effects that cannot be quantified or monetized.

Moreover, it may also be the case that the monetization of external costs is able to draw more attention to the environmental and social effects of electricity generation, in general and specific supply alternatives, in particular. This may provide an incentive to revisit local acceptability concerns of specific generation alternatives from a different perspective in the future.

It has been noted that one of the major strengths of social cost assessment is that it can help evaluate the trade-offs of each generation alternative. In implementing such an assessment it quickly becomes apparent that every generation alternative is associated with varying degrees of economic, social and environmental effects and there is not one particular option that objectively satisfies all requirements. Therefore, the results of this assessment imply that measures to reduce the 7,000 MW supply gap (i.e. conservation and demand-side management initiatives) can avoid having to decide among imperfect

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[241] For instance, the other generation alternatives under evaluation utilize depletable resources that will eventually be exhausted in the long-term, which will require a transition to renewable sources such as wind. According to Teitenberg (2000, p. 173), "Ultimately our energy needs will have to be fulfilled from renewable energy sources, either because the depletable energy sources have been exhausted or, as is more likely, the environmental costs of using the depletable sources have become so high that renewable sources will be cheaper". Moreover, the private costs of wind generation are expected to decline in real terms in the future relative to the other generation alternatives and encouraging its development may be able to accelerate wind power's competitiveness (IEA, 2000; NEB, 2006). It has also been noted that the scalability benefits associated with wind generation are not reflected in social cost estimates and it is widely accepted that a diverse supply mix can increase system reliability.

generation alternatives and therefore would reduce the magnitude of the consequences if the decision taken turned out to be incorrect (i.e. if the social costs were not minimized).

7.3.5 Internalizationconsiderations

The strategy to internalize external costs that was utilized in this assessment was to determine a capacity expansion scenario that included the generation alternative(s) with the lowest social costs. However, various other internalization mechanisms exist from Pigouvian taxes to cap-and-trade regulations to subsidizing low social cost generation alternatives based on their ability to reduce social costs. These mechanisms should be considered for further research to understand if another way of internalizing external costs would be more effective than the tool evaluated here. Regardless of which internalization mechanism is utilized, however, future research should also contemplate the significance of any macroeconomic consequences associated with internalization. For instance, expanding supply capacity with generation alternatives that have the lowest social costs may in fact increase the private costs incurred by electricity consumers, which may in turn lead to adverse consequences for the Ontario economy. Such consequences were not evaluated in this assessment since they were not identified in the computable burden assessment, but they could presumably be non-negligible.[242]

In addition, since the price of electricity is very "politically-charged", a deeper understanding of the political influences which may be a barrier to implementing internalization mechanisms should also be evaluated in future research (Owen, 2006). For instance, various politically influential special interest groups may be disproportionately affected by the internalization of external costs, which may limit the effectiveness of whichever policy is employed. In this case, policies that aim to curb undesirable distributional effects such as mechanisms that reduce impacts on low-income households and small businesses could be introduced. It is likely that broad support from the general public will be needed and various distributional effects must be acceptable in order for internalization mechanisms to succeed.

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[242] Whether innovation and productivity gains spurred by private cost increases (as noted by Gibbons, 2005) have the ability to offset adverse effects on the macro economy should be considered as well.

7.3.6 Contribution to the literature and future research opportunities

Very few studies in Ontario have evaluated the external costs of electricity generation alternatives (for example Chernick et al., 1993 and Venema and Barg, 2003). Even fewer have evaluated electricity generation alternatives using a primarily bottom-up methodology over the complete fuel cycle (Ontario Hydro, 1996). And, only one has examined social costs using the primarily bottom-up damage cost method for external costs (DSS for MOE, 2005). Whereas DSS for MOE (2005) assessed the social costs associated for coal-fired generation alternatives and natural gas-fired generation, the research undertaken here contributed to the breadth of electricity generation alternatives evaluated in the literature in Ontario by assessing the social costs of nuclear-fired generation and wind-powered generation in addition to natural gas-fired generation.[243] In addition, this research project aimed to increase the standard for social cost assessments undertaken in Ontario in terms of evaluating private and external costs of generation alternatives in a consistent, transparent and comprehensive manner.

However, it is noted that more research can be carried out in the future to add to the depth and breadth of the literature in this area. Future social cost research would benefit from original cost estimates rather than secondary data. In addition, other generation alternatives or conservation and demand-side management options (e.g. small-scale hydro or smart meters), as well different technologies for the generation alternatives evaluated here (e.g. combined heat and power utilizing natural gas, off-shore wind or Advanced Candu Reactors), or even combining generation options (e.g. wind power coupled with large-scale hydro or natural gas) could be assessed in future research.

[243] It is noted that a scenario combining natural gas and nuclear, which did not consider the external effects of nuclear-fired electricity generation was also evaluated in DSS for MOE (2005).

7.4 Chapter summary

In this chapter, the social cost estimates and the capacity expansion plan based on such figures were summarized. Various implications of these findings were considered in terms of potential policy options. Despite the limitations, it was argued that a social cost assessment that is consistent, transparent and comprehensive – while unable to produce a capacity expansion that definitively minimizes social costs – is one tool that can be used within a suite of evaluation criteria to enhance capacity expansion planning. Doing so could help clarify the relative importance of the trade-offs of each generation alternative, which can increase the likelihood that social costs of capacity expansion allocations are minimized.

Appendix A. Conversion table

Original unit	Conversion unit
Kilowatt (kW)	1,000 Watts
Megawatt (MW)	1,000 Kilowatts (kW)
Gigawatt (GW)	1,000 Megawatts (MW)
Terawatt (TW)	1,000 Gigawatts (GW)
Kilowatt-hour (kWh)	kW x 24
Gigajoule (GJ)	0.948 Million British Thermal Units (MMBtu)
Million British Thermal Unit (MMBtu)	1.055 Gigajoule (GJ)
Thousand Cubic Feet (Mcf)	Million British Thermal Unit (MMBtu)
Million Cubic Feet (MMcf)	1,000 Thousand Cubic Feet (Mcf)
Billion Cubic Feet (Bcf)	1,000 Million Cubic Feet (MMcf)
Trillion Cubic Feet (Tcf)	1,000 Billion Cubic Feet (Bcf)

Appendix B. Regulated and retail electricity rates

Non-smart meter regulated rates

Designated consumers and residential and small business consumers using less than 250,000 kWh per year that do not have an interval meter pay electricity rates that are regulated by the Ontario Energy Board. This rate currently rests at \$0.058/kWh for the first 600 kWh of electricity consumed per month and then goes to \$0.067/kWh for each additional kWh used thereafter (OEB website, 2006).[244] Regulated rates reflect the wholesale market price of electricity and any difference between the forecasted rate (that regulated consumers are obliged to pay) and the actual wholesale rate that is incurred during the same period will be carried forward and blended into the rate for the next 6 month period (i.e. the difference between the forecasted and the actual rate are rolled into the price for the next rate period). As a result, the wholesale rate and the regulated rate per kWh are similar, except for the fact that regulated consumers' prices are "smoothed out" over the course of each period. This smoothing process has the effect of insulating regulated consumers from the short-term price volatility that wholesale consumers are exposed to but it also reduces their incentive to manage their time-of-use.

Smart meter rates

Another initiative that is in the process of being introduced in Ontario is the use of smart meters. Such meters track the amount of electricity used and the time at which it is consumed and consumers are charged a different rate depending on the time of day in order to provide an incentive to reduce or shift demand to off-peak times. Three price periods throughout the day have been established: On-peak (when demand is highest), mid-peak (when demand is moderate) and off-peak (when demand is lowest) and these periods are different in the summer and the winter (refer to Figure B-0-1 for a list of rates). Consumers who have been equipped with a meter as of May 1, 2006 are required

[244] From May 1, 2006 to October 31, 2006 this threshold remains at 600 kWh per month, increasing to 1,000 kWh per month from November 1, 2006 to April 30, 2007. These rates are subject to change after April 30, 2007 (OEB, 2006).

to pay these rates and by 2010 all regulated Ontario electricity consumers will be outfitted with a smart meter.[245]

Figure B-1: Smart meter rates

Time of Day	Summer (May 1 – Oct 31) ($/kWh)	Winter (Nov 1 – Apr 30 ($/kWh)
Weekends & holidays	0.035	0.035
7 am – 11 am	0.075	0.105
11 am – 5 pm	0.105	0.075
5 pm – 8 pm	0.075	0.105
8 pm - 10 pm	0.075	0.075
10 pm – 7 am	0.035	0.035

source: OEB (2006)

Retail rates

Consumers also have the option of entering into a fixed price contract with a competitive electricity retailer for short or long term durations.

[245] Business owners and residential consumers in large urban areas will be the first to be outfitted.

Appendix C. Excel spreadsheets

The following excel spreadsheets are included in appendix C:

- Appendix C (i): LUEC Calculation Explanation
- Appendix C (ii): LUEC Analysis
- Appendix C (iii): Computable External Burden Assessment

Appendix C (i): LUEC Calculation Explanation		Construction period		Unit comes online	Calculation Explanation
Wind: Merchant Perspective	**Assumptions**	**2006**	**2007**	**2008**	
Private Costs		**Year -2**	**Year -1**	**Year 1**	
Revenue		$0	$0	$773,714	Revenue = annual number of kWh of electricity produced (4,888,080) x private cost of electricity per unit ($/kWh)
Capital costs ($/kW)	$1,845	$1,660,500	$1,660,500		Total capital costs = generating unit capacity (1.8 MW) x overnight capital costs ($1,845/kW) x 1,000. To determine the annual capital expenditure, total capital costs are allocated evenly over the construction period (unless otherwise noted)
Integration & balancing costs ($/kWh)	$0.005	$0	$0	$24,440	Annual integration and balancing cost = unit cost ($0.005/kWh) x annual number of kWh of electricity produced (4,888,080)
O&M costs ($/kWh)	$0.015	$0	$0	$73,321	Annual O&M cost = unit cost ($0.015/kWh) x annual number of kWh of electricity produced (4,888,080)
Net income before depreciation and tax		$0	$0	$675,953	Net income before depreciation & tax = revenue - (sum of integration and O&M). Note: fuel or other costs would be subtracted from revenue where applicable
Depreciation	$118,607	$0	$0	$118,607	Annual depreciation = total capital costs / number of years of expected operating life (28)
Taxes (%)	36%	$0	$0	$200,644	Annual income tax = (revenue before depreciation and tax - depreciation) x tax rate (36%)
Net income after depreciation and tax		$0	$0	$356,701	Net income after depreciation and tax = net income before depreciation & tax - depreciation - tax
Add back depreciation for cash flow	$118,607	$0	$0	$118,607	Depreciation is a non-cash flow item
Annual cash flow		-$1,660,500	-$1,660,500	$475,308	Annual cash flow = net income after depreciation and tax + depreciation
Private cost ($/kWh)	$0.158				Microsoft solver tool is used to determine the private unit cost of electricity by setting the NPV of the annual cash flows equal to zero
NPV annual private cost (13.0% merchant discount rate)	-$0.00				NPV is calculated using a discount rate of 13.0%, which is equal to the cost of capital for an all-equity firm
Planning Assumptions					
Generating unit net capacity (MW)	1.8				Explained in Chapter Five
Average capacity factor (%)	31%				Explained in Chapter Five
Electricity generated per year (kWh)		0	0	4,888,080	Generating unit capacity (1.8 MW) x average capacity factor (31%) x 365 x 24 x 1,000
Operating life (years)	28				Explained in Chapter Five
Construction duration (years)	2				Explained in Chapter Five
Cost of equity (%)	13.0%				Explained in Chapter Four
Computable External Costs					
Premature mortality ($/kWh)	$0.00238				Explained in Chapter Five
Climate change ($/kWh)	$0.00022				Explained in Chapter Five
Noise disturbance ($/kWh)	$0.00018				Explained in Chapter Five
Visual intrusion ($/kWh)	$0.00300				Explained in Chapter Five
Land use ($/kWh)	$0.00001				Explained in Chapter Five
Total computable external costs ($/kWh)	$0.006				Total computable external costs ($/kWh) = sum of individual computable external burdens
Total Social Costs ($/kWh)	$0.164				Total social costs ($/kWh) = private cost ($/kWh) + total computable external costs ($/kWh)

Appendix C (ii)		Construction period		Unit comes online				
Natural Gas: Public Perspective	**Assumptions**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**
Private Costs		**Year -2**	**Year -1**	**Year 1**	**Year 2**	**Year 3**	**Year 4**	**Year 5**
Revenue		$0	$0	$216,511,606	$216,511,606	$216,511,606	$216,511,606	$216,511,606
Capital costs: facility ($/kW)	$846	$211,500,000	$211,500,000					
Capital costs: infrastructure upgrades ($/kW)	$138	$0	$0					$69,000,000
Fixed O&M costs ($/kW)	$16.23	$0	$0	$8,115,000	$8,115,000	$8,115,000	$8,115,000	$8,115,000
Variable O&M costs ($/kWh)	$0.00317	$0	$0	$11,524,218	$11,524,218	$11,524,218	$11,524,218	$11,524,218
Fuel costs ($/kWh)	shown below	$0	$0	$178,311,159	$175,483,318	$172,710,925	$169,992,892	$167,328,154
Annual cash flow		-$211,500,000	-$211,500,000	$18,561,229	$21,389,070	$24,161,463	$26,879,496	-$39,455,767
Private cost ($/kWh)	$0.060							
NPV annual private costs (5% public discount rate)	$0.00							
Planning Assumpions								
Generating unit net capacity (MW)	500							
Average capacity factor (%)	83%							
Electricity generated per year (kWh)		0	0	3,635,400,000	3,635,400,000	3,635,400,000	3,635,400,000	3,635,400,000
Operating life (years)	27							
Construction duration (years)	2							
Inflation (%)	2%							
Cost of long-term public debt	5%							
Fuel cost assumptions								
NRCan (2006) (CDN$/Mcf)-nominal, average		$5.92	$5.92	$5.92	$5.92	$5.92	$5.92	$5.92
NRCan (2006) (CDN$/Mcf)-inflation-adjusted (real 2006 CDN$)		$5.92	$5.81	$5.69	$5.58	$5.47	$5.37	$5.26
EIA AEO (2006) (CDN$/Mcf) (real 2006 CDN$)		n/a	n/a	n/a	n/a	n/a	n/a	n/a
Commodity cost ($/Mcf)		$5.92	$5.81	$5.69	$5.58	$5.47	$5.37	$5.26
AECO-NYMEX price differential ($/Mcf)		n/a	n/a	n/a	n/a	n/a	n/a	n/a
Transportation cost ($/Mcf)		$1.00	$1.00	$1.00	$1.00	$1.00	$1.00	$1.00
Storage and distribution cost ($/Mcf)		$0.34	$0.34	$0.34	$0.34	$0.34	$0.34	$0.34
Price volatility cost ($/Mcf)		$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01
Net fuel cost ($/Mcf)		$7.27	$7.15	$7.04	$6.93	$6.82	$6.71	$6.61
Heat rate (Mcf/kWh)	0.006967	0.00697	0.00697	0.00697	0.00697	0.00697	0.00697	0.00697
Fuel costs ($/kWh)		$0.0507	$0.0498	$0.0490	$0.0483	$0.0475	$0.0468	$0.0460
Computable External Costs								
Climate change ($/kWh)	$0.005							
Premature mortality ($/kWh)	$0.016							
Total computable external costs ($/kWh)	$0.021							
Total Social Costs ($/kWh)	$0.081							

Natural Gas: Public Perspective	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Private Costs	**Year 6**	**Year 7**	**Year 8**	**Year 9**	**Year 10**	**Year 11**	**Year 12**	**Year 13**	**Year 14**	**Year 15**	**Year 16**
Revenue	$216,511,606	$216,511,606	$216,511,606	$216,511,606	$216,511,606	$216,511,606	$216,511,606	$216,511,606	$216,511,606	$216,511,606	$216,511,606
Fixed O&M costs ($/kW)	$8,115,000	$8,115,000	$8,115,000	$8,115,000	$8,115,000	$8,115,000	$8,115,000	$8,115,000	$8,115,000	$8,115,000	$8,115,000
Variable O&M costs ($/kWh)	$11,524,218	$11,524,218	$11,524,218	$11,524,218	$11,524,218	$11,524,218	$11,524,218	$11,524,218	$11,524,218	$11,524,218	$11,524,218
Fuel costs ($/kWh)	$164,715,666	$162,154,403	$159,643,361	$167,028,779	$164,422,161	$161,866,653	$159,361,253	$156,904,979	$128,492,405	$135,538,796	$142,585,186
Annual cash flow	$32,156,722	$34,717,984	$37,229,026	$29,843,609	$32,450,227	$35,005,735	$37,511,134	$39,967,409	$68,379,983	$61,333,592	$54,287,201
Electricity generated per year (kWh)	3,635,400,000	3,635,400,000	3,635,400,000	3,635,400,000	3,635,400,000	3,635,400,000	3,635,400,000	3,635,400,000	3,635,400,000	3,635,400,000	3,635,400,000
NRCan (2006) (CDN$/Mcf)-nominal, average	$5.92	$5.92	$5.92	$6.40	$6.40	$6.40	$6.40	$6.40			
NRCan (2006) (CDN$/Mcf)-inflation-adjusted (real 2006 CDN$)	$5.16	$5.06	$4.96	$5.25	$5.15	$5.04	$4.95	$4.85			
EIA AEO (2006) (CDN$/Mcf) (real 2006 CDN$)	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	$5.13	$5.41	$5.68
Commodity cost ($/Mcf)	$5.16	$5.06	$4.96	$5.25	$5.15	$5.04	$4.95	$4.85	$5.13	$5.41	$5.68
AECO-NYMEX price differential ($/Mcf)	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	($0.55)	($0.55)	($0.55)
Transportation cost ($/Mcf)	$1.00	$1.00	$1.00	$1.00	$1.00	$1.00	$1.00	$1.00	$0.15	$0.15	$0.15
Storage and distribution cost ($/Mcf)	$0.34	$0.34	$0.34	$0.34	$0.34	$0.34	$0.34	$0.34	$0.34	$0.34	$0.34
Price volatility cost ($/Mcf)	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01
Net fuel cost ($/Mcf)	$6.50	$6.40	$6.30	$6.59	$6.49	$6.39	$6.29	$6.19	$5.07	$5.35	$5.63
Heat rate (Mcf/kWh)	0.00697	0.00697	0.00697	0.00697	0.00697	0.00697	0.00697	0.00697	0.00697	0.00697	0.00697
Fuel costs ($/kWh)	$0.0453	$0.0446	$0.0439	$0.0459	$0.0452	$0.0445	$0.0438	$0.0432	$0.0353	$0.0373	$0.0392

Natural Gas: Public Perspective	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
Private Costs	**Year 17**	**Year 18**	**Year 19**	**Year 20**	**Year 21**	**Year 22**	**Year 23**	**Year 24**	**Year 25**	**Year 26**	**Year 27**
Revenue	$216,511,606	$216,511,606	$216,511,606	$216,511,606	$216,511,606	$216,511,606	$216,511,606	$216,511,606	$216,511,606	$216,511,606	$216,511,606
Fixed O&M costs ($/kW)	$8,115,000	$8,115,000	$8,115,000	$8,115,000	$8,115,000	$8,115,000	$8,115,000	$8,115,000	$8,115,000	$8,115,000	$8,115,000
Variable O&M costs ($/kWh)	$11,524,218	$11,524,218	$11,524,218	$11,524,218	$11,524,218	$11,524,218	$11,524,218	$11,524,218	$11,524,218	$11,524,218	$11,524,218
Fuel costs ($/kWh)	$149,631,577	$156,677,968	$159,514,685	$162,351,402	$165,188,119	$168,024,836	$170,861,553	$172,583,846	$174,323,361	$176,080,272	$177,854,752
Annual cash flow	$47,240,811	$40,194,420	$37,357,703	$34,520,986	$31,684,269	$28,847,551	$26,010,834	$24,288,542	$22,549,026	$20,792,116	$19,017,636
Electricity generated per year (kWh)	3,635,400,000	3,635,400,000	3,635,400,000	3,635,400,000	3,635,400,000	3,635,400,000	3,635,400,000	3,635,400,000	3,635,400,000	3,635,400,000	3,635,400,000
EIA AEO (2006) (CDN$/Mcf) (real 2006 CDN$)	$5.96	$6.24	$6.35	$6.46	$6.58	$6.69	$6.80	$6.87	$6.94	$7.01	$7.08
Commodity cost ($/Mcf)	$5.96	$6.24	$6.35	$6.46	$6.58	$6.69	$6.80	$6.87	$6.94	$7.01	$7.08
AECO-NYMEX price differential ($/Mcf)	($0.55)	($0.55)	($0.55)	($0.55)	($0.55)	($0.55)	($0.55)	($0.55)	($0.55)	($0.55)	($0.55)
Transportation cost ($/Mcf)	$0.15	$0.15	$0.15	$0.15	$0.15	$0.15	$0.15	$0.15	$0.15	$0.15	$0.15
Storage and distribution cost ($/Mcf)	$0.34	$0.34	$0.34	$0.34	$0.34	$0.34	$0.34	$0.34	$0.34	$0.34	$0.34
Price volatility cost ($/Mcf)	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01
Net fuel cost ($/Mcf)	$5.91	$6.19	$6.30	$6.41	$6.52	$6.63	$6.75	$6.81	$6.88	$6.95	$7.02
Heat rate (Mcf/kWh)	0.00697	0.00697	0.00697	0.00697	0.00697	0.00697	0.00697	0.00697	0.00697	0.00697	0.00697
Fuel costs ($/kWh)	$0.0412	$0.0431	$0.0439	$0.0447	$0.0454	$0.0462	$0.0470	$0.0475	$0.0480	$0.0484	$0.0489

Appendix C (ii)		Construction period		Unit comes online					
Natural Gas: Merchant Perspective	**Assumptions**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**
Private Costs		**Year -2**	**Year -1**	**Year 1**	**Year 2**	**Year 3**	**Year 4**	**Year 5**	**Year 6**
Revenue		$0	$0	$276,877,579	$276,877,579	$276,877,579	$276,877,579	$276,877,579	$276,877,579
Capital costs: facility ($/kW)	$846	$211,500,000	$211,500,000						
Capital costs: infrastructure upgrades ($/kW)	$138	$0	$0					$69,000,000	
Fixed O&M costs ($/kW)	$16.23	$0	$0	$8,115,000	$8,115,000	$8,115,000	$8,115,000	$8,115,000	$8,115,000
Variable O&M costs ($/kWh)	$0.00317	$0	$0	$11,524,218	$11,524,218	$11,524,218	$11,524,218	$11,524,218	$11,524,218
Fuel costs ($/kWh)	shown below	$0	$0	$178,311,159	$175,483,318	$172,710,925	$169,992,892	$167,328,154	$164,715,666
Net income before depreciation and tax		$0	$0	$78,927,202	$81,755,043	$84,527,437	$87,245,469	$20,910,207	$92,522,695
Depreciation	$15,666,667	$0	$0	$15,666,667	$15,666,667	$15,666,667	$15,666,667	$15,666,667	$15,666,667
Taxes (%)	36%	$0	$0	$22,773,793	$23,791,816	$24,789,877	$25,768,369	$1,887,675	$27,668,170
Net income after depreciation and tax		$0	$0	$40,486,743	$42,296,561	$44,070,893	$45,810,434	$3,355,866	$49,187,858
Add back depreciation for cash flow	$15,666,667	$0	$0	$15,666,667	$15,666,667	$15,666,667	$15,666,667	$15,666,667	$15,666,667
Annual cash flow		-$211,500,000	-$211,500,000	$56,153,409	$57,963,228	$59,737,559	$61,477,100	$19,022,532	$64,854,525
Private cost ($/kWh)	$0.076								
NPV annual private costs (13.0% merchant discount rate)	$0.00								
Planning Assumptions									
Generating unit net capacity (MW)	500								
Average capacity factor (%)	83%								
Electricity generated per year (kWh)		0	0	3,635,400,000	3,635,400,000	3,635,400,000	3,635,400,000	3,635,400,000	3,635,400,000
Operating life (years)	27								
Construction duration (years)	2								
Inflation (%)	2%								
Cost of equity (%)	13.0%								
Fuel cost assumptions									
NRCan (2006) (CDN$/Mcf)-nominal, average		$5.92	$5.92	$5.92	$5.92	$5.92	$5.92	$5.92	$5.92
NRCan (2006) (CDN$/Mcf)-inflation-adjusted (real 2006 CDN$)		$5.92	$5.81	$5.69	$5.58	$5.47	$5.37	$5.26	$5.16
EIA AEO (2006) (CDN$/Mcf) (real 2006 CDN$)		n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Commodity cost ($/Mcf)		$5.92	$5.81	$5.69	$5.58	$5.47	$5.37	$5.26	$5.16
AECO-NYMEX price differential ($/Mcf)		n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Transportation cost ($/Mcf)		$1.00	$1.00	$1.00	$1.00	$1.00	$1.00	$1.00	$1.00
Storage and distribution cost ($/Mcf)		$0.34	$0.34	$0.34	$0.34	$0.34	$0.34	$0.34	$0.34
Price volatility cost ($/Mcf)		$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01
Net fuel cost ($/Mcf)		$7.27	$7.15	$7.04	$6.93	$6.82	$6.71	$6.61	$6.50
Heat rate (Mcf/kWh)	0.006967	0.00697	0.00697	0.00697	0.00697	0.00697	0.00697	0.00697	0.00697
Fuel costs ($/kwh)		$0.0507	$0.0498	$0.0490	$0.0483	$0.0475	$0.0468	$0.0460	$0.0453
Computable External Costs									
Climate change ($/kWh)	$0.005								
Premature mortality ($/kWh)	$0.016								
Total computable external costs ($/kWh)	$0.021								
Total Social Costs ($/kWh)	$0.097								

	2014	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Private Costs	**Year 7**	**Year 8**	**Year 9**	**Year 10**	**Year 11**	**Year 12**	**Year 13**	**Year 14**	**Year 15**	**Year 16**
Revenue	$276,877,579	$276,877,579	$276,877,579	$276,877,579	$276,877,579	$276,877,579	$276,877,579	$276,877,579	$276,877,579	$276,877,579
Capital costs: facility ($/kW)										
Capital costs: infrastructure upgrades ($/kW)										
Fixed O&M costs ($/kW)	$8,115,000	$8,115,000	$8,115,000	$8,115,000	$8,115,000	$8,115,000	$8,115,000	$8,115,000	$8,115,000	$8,115,000
Variable O&M costs ($/kWh)	$11,524,218	$11,524,218	$11,524,218	$11,524,218	$11,524,218	$11,524,218	$11,524,218	$11,524,218	$11,524,218	$11,524,218
Fuel costs ($/kWh)	$162,154,403	$159,643,361	$167,028,779	$164,422,161	$161,866,653	$159,361,253	$156,904,979	$128,492,405	$135,538,796	$142,585,186
Net income before depreciation and tax	$95,083,958	$97,595,000	$90,209,582	$92,816,200	$95,371,708	$97,877,108	$100,333,382	$128,745,956	$121,699,566	$114,653,175
Depreciation	$15,666,667	$15,666,667	$15,666,667	$15,666,667	$15,666,667	$15,666,667	$15,666,667	$15,666,667	$15,666,667	$15,666,667
Taxes (%)	$28,590,225	$29,494,200	$26,835,450	$27,773,832	$28,693,815	$29,595,759	$30,480,018	$40,708,544	$38,171,844	$35,635,143
Net income after depreciation and tax	$50,827,066	$52,434,133	$47,707,466	$49,375,702	$51,011,227	$52,614,682	$54,186,698	$72,370,745	$67,861,055	$63,351,365
Add back depreciation for cash flow	$15,666,667	$15,666,667	$15,666,667	$15,666,667	$15,666,667	$15,666,667	$15,666,667	$15,666,667	$15,666,667	$15,666,667
Annual cash flow	$66,493,733	$68,100,800	$63,374,133	$65,042,368	$66,677,893	$68,281,349	$69,853,365	$88,037,412	$83,527,722	$79,018,032
Electricity generated per year (kWh)	3,635,400,000	3,635,400,000	3,635,400,000	3,635,400,000	3,635,400,000	3,635,400,000	3,635,400,000	3,635,400,000	3,635,400,000	3,635,400,000
NRCan (2006) (CDN$/Mcf)-nominal, average	$5.92	$5.92	$6.40	$6.40	$6.40	$6.40	$6.40			
NRCan (2006) (CDN$/Mcf)-inflation-adjusted (real 2006 CDN$)	$5.06	$4.96	$5.25	$5.15	$5.04	$4.95	$4.85			
EIA AEO (2006) (CDN$/Mcf) (real 2006 CDN$)	n/a	n/a	n/a	n/a	n/a	n/a	n/a	$5.13	$5.41	$5.68
Commodity cost ($/Mcf)	$5.06	$4.96	$5.25	$5.15	$5.04	$4.95	$4.85	$5.13	$5.41	$5.68
AECO-NYMEX price differential ($/Mcf)	n/a	n/a	n/a	n/a	n/a	n/a	n/a	($0.55)	($0.55)	($0.55)
Transportation cost ($/Mcf)	$1.00	$1.00	$1.00	$1.00	$1.00	$1.00	$1.00	$0.15	$0.15	$0.15
Storage and distribution cost ($/Mcf)	$0.34	$0.34	$0.34	$0.34	$0.34	$0.34	$0.34	$0.34	$0.34	$0.34
Price volatility cost ($/Mcf)	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01
Net fuel cost ($/Mcf)	$6.40	$6.30	$6.59	$6.49	$6.39	$6.29	$6.19	$5.07	$5.35	$5.63
Heat rate (Mcf/kWh)	0.00697	0.00697	0.00697	0.00697	0.00697	0.00697	0.00697	0.00697	0.00697	0.00697
Fuel costs ($/kwh)	$0.0446	$0.0439	$0.0459	$0.0452	$0.0445	$0.0438	$0.0432	$0.0353	$0.0373	$0.0392

	2024	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
Private Costs	**Year 17**	**Year 18**	**Year 19**	**Year 20**	**Year 21**	**Year 22**	**Year 23**	**Year 24**	**Year 25**	**Year 26**	**Year 27**
Revenue	$276,877,579	$276,877,579	$276,877,579	$276,877,579	$276,877,579	$276,877,579	$276,877,579	$276,877,579	$276,877,579	$276,877,579	$276,877,579
Capital costs: facility ($/kW)											
Capital costs: infrastructure upgrades ($/kW)											
Fixed O&M costs ($/kW)	$8,115,000	$8,115,000	$8,115,000	$8,115,000	$8,115,000	$8,115,000	$8,115,000	$8,115,000	$8,115,000	$8,115,000	$8,115,000
Variable O&M costs ($/kWh)	$11,524,218	$11,524,218	$11,524,218	$11,524,218	$11,524,218	$11,524,218	$11,524,218	$11,524,218	$11,524,218	$11,524,218	$11,524,218
Fuel costs ($/kWh)	$149,631,577	$156,677,968	$159,514,685	$162,351,402	$165,188,119	$168,024,836	$170,861,553	$172,583,846	$174,323,361	$176,080,272	$177,854,752
Net income before depreciation and tax	$107,606,784	$100,560,394	$97,723,677	$94,886,959	$92,050,242	$89,213,525	$86,376,808	$84,654,515	$82,915,000	$81,158,089	$79,383,609
Depreciation	$15,666,667	$15,666,667	$15,666,667	$15,666,667	$15,666,667	$15,666,667	$15,666,667	$15,666,667	$15,666,667	$15,666,667	$15,666,667
Taxes (%)	$33,098,442	$30,561,742	$29,540,524	$28,519,305	$27,498,087	$26,476,869	$25,455,651	$24,835,626	$24,209,400	$23,576,912	$22,938,099
Net income after depreciation and tax	$58,841,675	$54,331,985	$52,516,486	$50,700,987	$48,885,488	$47,069,989	$45,254,490	$44,152,223	$43,038,933	$41,914,510	$40,778,843
Add back depreciation for cash flow	$15,666,667	$15,666,667	$15,666,667	$15,666,667	$15,666,667	$15,666,667	$15,666,667	$15,666,667	$15,666,667	$15,666,667	$15,666,667
Annual cash flow	$74,508,342	$69,998,652	$68,183,153	$66,367,654	$64,552,155	$62,736,656	$60,921,157	$59,818,890	$58,705,600	$57,581,177	$56,445,510
Electricity generated per year (kWh)	3,635,400,000	3,635,400,000	3,635,400,000	3,635,400,000	3,635,400,000	3,635,400,000	3,635,400,000	3,635,400,000	3,635,400,000	3,635,400,000	3,635,400,000
EIA AEO (2006) (CDN$/Mcf) (real 2006 CDN$)	$5.96	$6.24	$6.35	$6.46	$6.58	$6.69	$6.80	$6.87	$6.94	$7.01	$7.08
Commodity cost ($/Mcf)	$5.96	$6.24	$6.35	$6.46	$6.58	$6.69	$6.80	$6.87	$6.94	$7.01	$7.08
AECO-NYMEX price differential ($/Mcf)	($0.55)	($0.55)	($0.55)	($0.55)	($0.55)	($0.55)	($0.55)	($0.55)	($0.55)	($0.55)	($0.55)
Transportation cost ($/Mcf)	$0.15	$0.15	$0.15	$0.15	$0.15	$0.15	$0.15	$0.15	$0.15	$0.15	$0.15
Storage and distribution cost ($/Mcf)	$0.34	$0.34	$0.34	$0.34	$0.34	$0.34	$0.34	$0.34	$0.34	$0.34	$0.34
Price volatility cost ($/Mcf)	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01
Net fuel cost ($/Mcf)	$5.91	$6.19	$6.30	$6.41	$6.52	$6.63	$6.75	$6.81	$6.88	$6.95	$7.02
Heat rate (Mcf/kWh)	0.00697	0.00697	0.00697	0.00697	0.00697	0.00697	0.00697	0.00697	0.00697	0.00697	0.00697
Fuel costs ($/kwh)	$0.0412	$0.0431	$0.0439	$0.0447	$0.0454	$0.0462	$0.0470	$0.0475	$0.0480	$0.0484	$0.0489

Appendix C (ii)		Construction period		Unit comes online								
Wind: Public Perspective	**Assumptions**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
Private Costs		**Year -2**	**Year -1**	**Year 1**	**Year 2**	**Year 3**	**Year 4**	**Year 5**	**Year 6**	**Year 7**	**Year 8**	**Year 9**
Revenue		$0	$0	$326,248	$326,248	$326,248	$326,248	$326,248	$326,248	$326,248	$326,248	$326,248
Capital costs ($/kW)	$1,845	$1,660,500	$1,660,500									
Integration & balancing costs ($/kWh)	$0.005	$0	$0	$24,440	$24,440	$24,440	$24,440	$24,440	$24,440	$24,440	$24,440	$24,440
O&M costs ($/kWh)	$0.015	$0	$0	$73,321	$73,321	$73,321	$73,321	$73,321	$73,321	$73,321	$73,321	$73,321
Annual cash flow		-$1,660,500	-$1,660,500	$228,487	$228,487	$228,487	$228,487	$228,487	$228,487	$228,487	$228,487	$228,487
Private cost ($/kWh)	$0.067											
NPV annual private costs (5% public discount rate)	-$0.00											
Planning Assumptions												
Generating unit net capacity (MW)	1.8											
Average capacity factor (%)	31%											
Electricity generated per year (kWh)		0	0	4,888,080	4,888,080	4,888,080	4,888,080	4,888,080	4,888,080	4,888,080	4,888,080	4,888,080
Operating life (years)	28											
Construction duration (years)	2											
Cost of long-term public debt	5%											
Computable External Costs												
Premature mortality ($/kWh)	$0.00238											
Climate change ($/kWh)	$0.00022											
Noise disturbance ($/kWh)	$0.00018											
Visual intrusion ($/kWh)	$0.00300											
Land use ($/kWh)	$0.00001											
Total computable external costs ($/kWh)	$0.006											
Total Social Costs ($/kWh)	$0.073											

Wind: Public Perspective	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Private Costs	**Year 10**	**Year 11**	**Year 12**	**Year 13**	**Year 14**	**Year 15**	**Year 16**	**Year 17**	**Year 18**
Revenue	$326,248	$326,248	$326,248	$326,248	$326,248	$326,248	$326,248	$326,248	$326,248
Integration & balancing costs ($/kWh)	$24,440	$24,440	$24,440	$24,440	$24,440	$24,440	$24,440	$24,440	$24,440
O&M costs ($/kWh)	$73,321	$73,321	$73,321	$73,321	$73,321	$73,321	$73,321	$73,321	$73,321
Annual cash flow	$228,487	$228,487	$228,487	$228,487	$228,487	$228,487	$228,487	$228,487	$228,487
Electricity generated per year (kWh)	4,888,080	4,888,080	4,888,080	4,888,080	4,888,080	4,888,080	4,888,080	4,888,080	4,888,080

Wind: Public Perspective	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
Private Costs	**Year 19**	**Year 20**	**Year 21**	**Year 22**	**Year 23**	**Year 24**	**Year 25**	**Year 26**	**Year 27**	**Year 28**
Revenue	$326,248	$326,248	$326,248	$326,248	$326,248	$326,248	$326,248	$326,248	$326,248	$326,248
Integration & balancing costs ($/kWh)	$24,440	$24,440	$24,440	$24,440	$24,440	$24,440	$24,440	$24,440	$24,440	$24,440
O&M costs ($/kWh)	$73,321	$73,321	$73,321	$73,321	$73,321	$73,321	$73,321	$73,321	$73,321	$73,321
Annual cash flow	$228,487	$228,487	$228,487	$228,487	$228,487	$228,487	$228,487	$228,487	$228,487	$228,487
Electricity generated per year (kWh)	4,888,080	4,888,080	4,888,080	4,888,080	4,888,080	4,888,080	4,888,080	4,888,080	4,888,080	4,888,080

Appendix C (ii)		Construction period		Unit comes online						
Wind: Merchant Perspective	**Assumptions**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**
Private Costs		**Year -2**	**Year -1**	**Year 1**	**Year 2**	**Year 3**	**Year 4**	**Year 5**	**Year 6**	**Year 7**
Revenue		$0	$0	$773,714	$773,714	$773,714	$773,714	$773,714	$773,714	$773,714
Capital costs ($/kW)	$1,845	$1,660,500	$1,660,500							
Integration & balancing costs ($/kWh)	$0.005	$0	$0	$24,440	$24,440	$24,440	$24,440	$24,440	$24,440	$24,440
O&M costs ($/kWh)	$0.015	$0	$0	$73,321	$73,321	$73,321	$73,321	$73,321	$73,321	$73,321
Net income before depreciation and tax		$0	$0	$675,953	$675,953	$675,953	$675,953	$675,953	$675,953	$675,953
Depreciation	$118,607	$0	$0	$118,607	$118,607	$118,607	$118,607	$118,607	$118,607	$118,607
Taxes (%)	36%	$0	$0	$200,644	$200,644	$200,644	$200,644	$200,644	$200,644	$200,644
Net income after depreciation and tax		$0	$0	$356,701	$356,701	$356,701	$356,701	$356,701	$356,701	$356,701
Add back depreciation for cash flow	$118,607	$0	$0	$118,607	$118,607	$118,607	$118,607	$118,607	$118,607	$118,607
Annual cash flow		-$1,660,500	-$1,660,500	$475,308	$475,308	$475,308	$475,308	$475,308	$475,308	$475,308
Private cost ($/kWh)	$0.158									
NPV annual private cost (13.0% merchant discount rate)	$0.00									
Planning Assumptions										
Generating unit net capacity (MW)	1.8									
Average capacity factor (%)	31%									
Electricity generated per year (kWh)		0	0	4,888,080	4,888,080	4,888,080	4,888,080	4,888,080	4,888,080	4,888,080
Operating life (years)	28									
Construction duration (years)	2									
Cost of equity (%)	13.0%									
Computable External Costs										
Premature mortality ($/kWh)	$0.00238									
Climate change ($/kWh)	$0.00022									
Noise disturbance ($/kWh)	$0.00018									
Visual intrusion ($/kWh)	$0.00300									
Land use ($/kWh)	$0.00001									
Total computable external costs ($/kWh)	$0.006									
Total Social Costs ($/kWh)	$0.164									

Appendix C (ii)										
Wind: Merchant Perspective	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Private Costs	**Year 8**	**Year 9**	**Year 10**	**Year 11**	**Year 12**	**Year 13**	**Year 14**	**Year 15**	**Year 16**	**Year 17**
Revenue	$773,714	$773,714	$773,714	$773,714	$773,714	$773,714	$773,714	$773,714	$773,714	$773,714
Capital costs ($/kW)										
Integration & balancing costs ($/kWh)	$24,440	$24,440	$24,440	$24,440	$24,440	$24,440	$24,440	$24,440	$24,440	$24,440
O&M costs ($/kWh)	$73,321	$73,321	$73,321	$73,321	$73,321	$73,321	$73,321	$73,321	$73,321	$73,321
Net income before depreciation and tax	$675,953	$675,953	$675,953	$675,953	$675,953	$675,953	$675,953	$675,953	$675,953	$675,953
Depreciation	$118,607	$118,607	$118,607	$118,607	$118,607	$118,607	$118,607	$118,607	$118,607	$118,607
Taxes (%)	$200,644	$200,644	$200,644	$200,644	$200,644	$200,644	$200,644	$200,644	$200,644	$200,644
Net income after depreciation and tax	$356,701	$356,701	$356,701	$356,701	$356,701	$356,701	$356,701	$356,701	$356,701	$356,701
Add back depreciation for cash flow	$118,607	$118,607	$118,607	$118,607	$118,607	$118,607	$118,607	$118,607	$118,607	$118,607
Annual cash flow	$475,308	$475,308	$475,308	$475,308	$475,308	$475,308	$475,308	$475,308	$475,308	$475,308
Private cost ($/kWh)										
NPV annual private cost (13.0% merchant discount rate)										
Planning Assumptions										
Generating unit net capacity (MW)										
Average capacity factor (%)										
Electricity generated per year (kWh)	4,888,080	4,888,080	4,888,080	4,888,080	4,888,080	4,888,080	4,888,080	4,888,080	4,888,080	4,888,080
Operating life (years)										
Construction duration (years)										
Cost of equity (%)										
Computable External Costs										
Premature mortality ($/kWh)										
Climate change ($/kWh)										
Noise disturbance ($/kWh)										
Visual intrusion ($/kWh)										
Land use ($/kWh)										
Total computable external costs ($/kWh)										
Total Social Costs ($/kWh)										

Appendix C (ii)											
Wind: Merchant Perspective	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
Private Costs	**Year 18**	**Year 19**	**Year 20**	**Year 21**	**Year 22**	**Year 23**	**Year 24**	**Year 25**	**Year 26**	**Year 27**	**Year 28**
Revenue	$773,714	$773,714	$773,714	$773,714	$773,714	$773,714	$773,714	$773,714	$773,714	$773,714	$773,714
Capital costs ($/kW)											
Integration & balancing costs ($/kWh)	$24,440	$24,440	$24,440	$24,440	$24,440	$24,440	$24,440	$24,440	$24,440	$24,440	$24,440
O&M costs ($/kWh)	$73,321	$73,321	$73,321	$73,321	$73,321	$73,321	$73,321	$73,321	$73,321	$73,321	$73,321
Net income before depreciation and tax	$675,953	$675,953	$675,953	$675,953	$675,953	$675,953	$675,953	$675,953	$675,953	$675,953	$675,953
Depreciation	$118,607	$118,607	$118,607	$118,607	$118,607	$118,607	$118,607	$118,607	$118,607	$118,607	$118,607
Taxes (%)	$200,644	$200,644	$200,644	$200,644	$200,644	$200,644	$200,644	$200,644	$200,644	$200,644	$200,644
Net income after depreciation and tax	$356,701	$356,701	$356,701	$356,701	$356,701	$356,701	$356,701	$356,701	$356,701	$356,701	$356,701
Add back depreciation for cash flow	$118,607	$118,607	$118,607	$118,607	$118,607	$118,607	$118,607	$118,607	$118,607	$118,607	$118,607
Annual cash flow	$475,308	$475,308	$475,308	$475,308	$475,308	$475,308	$475,308	$475,308	$475,308	$475,308	$475,308
Private cost ($/kWh)											
NPV annual private cost (13.0% merchant discount rate)											
Planning Assumptions											
Generating unit net capacity (MW)											
Average capacity factor (%)											
Electricity generated per year (kWh)	4,888,080	4,888,080	4,888,080	4,888,080	4,888,080	4,888,080	4,888,080	4,888,080	4,888,080	4,888,080	4,888,080
Operating life (years)											
Construction duration (years)											
Cost of equity (%)											
Computable External Costs											
Premature mortality ($/kWh)											
Climate change ($/kWh)											
Noise disturbance ($/kWh)											
Visual intrusion ($/kWh)											
Land use ($/kWh)											
Total computable external costs ($/kWh)											
Total Social Costs ($/kWh)											

Appendix C (ii)		First unit construction period		First unit comes online					
Nuclear Refurbishment: Public Perspective	**Assumptions**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**
Private Costs		**Year -2**	**Year -1**	**Year 1**	**Year 2**	**Year 3**	**Year 4**	**Year 5**	**Year 6**
Revenue		$0	$0	$258,987,046	$258,987,046	$258,987,046	$258,987,046	$258,987,046	$258,987,046
Capital costs ($/kW)	$1,922	$722,672,000	$722,672,000						
O&M costs ($/kWh)	$0.01362	$0	$0	$72,674,838	$72,674,838	$72,674,838	$72,674,838	$72,674,838	$72,674,838
Fuel costs ($/kWh)	$0.00276	$0	$0	$14,727,060	$14,727,060	$14,727,060	$14,727,060	$14,727,060	$14,727,060
Waste management costs ($/kWh)	$0.00155	$0	$0	$8,270,631	$8,270,631	$8,270,631	$8,270,631	$8,270,631	$8,270,631
Decommissioning costs ($/kWh)	$0.00105	$0	$0	$5,602,686	$5,602,686	$5,602,686	$5,602,686	$5,602,686	$5,602,686
Annual cash flow		-$722,672,000	-$722,672,000	$157,711,831	$157,711,831	$157,711,831	$157,711,831	$157,711,831	$157,711,831
Private cost ($/kWh)	$0.049								
NPV annual private costs (5% public discount rate)	-$0.00								
Planning Assumptions									
Generating unit net capacity (MW)	752								
Average capacity factor (%)	81%								
Electricity generated per year (kWh)		0	0	5,335,891,200	5,335,891,200	5,335,891,200	5,335,891,200	5,335,891,200	5,335,891,200
Operating life (years)	26								
Construction duration (years)	2								
Cost of long-term public debt	5%								
Computable External Costs									
Severe accidents ($/kWh)	$0.002								
Health costs associated with radioactive emissions ($/kWh)	$0.007								
Total computable external costs ($/kWh)	$0.009								
Total Social Costs ($/kWh)	$0.058								

Appendix C (ii)						Second unit construction period		Second unit comes online		
Nuclear Refurbishment: Public Perspective	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Private Costs	**Year 7**	**Year 8**	**Year 9**	**Year 10**	**Year 11**	**Year 12**	**Year 13**	**Year 14**	**Year 15**	**Year 16**
Revenue	$258,987,046	$258,987,046	$258,987,046	$258,987,046	$258,987,046	$258,987,046	$258,987,046	$258,987,046	$258,987,046	$258,987,046
Capital costs ($/kW)						$722,672,000	$722,672,000			
O&M costs ($/kWh)	$72,674,838	$72,674,838	$72,674,838	$72,674,838	$72,674,838	$72,674,838	$72,674,838	$72,674,838	$72,674,838	$72,674,838
Fuel costs ($/kWh)	$14,727,060	$14,727,060	$14,727,060	$14,727,060	$14,727,060	$14,727,060	$14,727,060	$14,727,060	$14,727,060	$14,727,060
Waste management costs ($/kWh)	$8,270,631	$8,270,631	$8,270,631	$8,270,631	$8,270,631	$8,270,631	$8,270,631	$8,270,631	$8,270,631	$8,270,631
Decommissioning costs ($/kWh)	$5,602,686	$5,602,686	$5,602,686	$5,602,686	$5,602,686	$5,602,686	$5,602,686	$5,602,686	$5,602,686	$5,602,686
Annual cash flow	$157,711,831	$157,711,831	$157,711,831	$157,711,831	$157,711,831	-$564,960,169	-$564,960,169	$157,711,831	$157,711,831	$157,711,831
Private cost ($/kWh)										
NPV annual private costs (5% public discount rate)										
Planning Assumptions										
Generating unit net capacity (MW)										
Average capacity factor (%)										
Electricity generated per year (kWh)	5,335,891,200	5,335,891,200	5,335,891,200	5,335,891,200	5,335,891,200	5,335,891,200	5,335,891,200	5,335,891,200	5,335,891,200	5,335,891,200
Operating life (years)										
Construction duration (years)										
Cost of long-term public debt										
Computable External Costs										
Severe accidents ($/kWh)										
Health costs associated with radioactive emissions ($/kWh)										
Total computable external costs ($/kWh)										
Total Social Costs ($/kWh)										

Appendix C (ii)										
Nuclear Refurbishment: Public Perspective	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
Private Costs	**Year 17**	**Year 18**	**Year 19**	**Year 20**	**Year 21**	**Year 22**	**Year 23**	**Year 24**	**Year 25**	**Year 26**
Revenue	$258,987,046	$258,987,046	$258,987,046	$258,987,046	$258,987,046	$258,987,046	$258,987,046	$258,987,046	$258,987,046	$258,987,046
Capital costs ($/kW)										
O&M costs ($/kWh)	$72,674,838	$72,674,838	$72,674,838	$72,674,838	$72,674,838	$72,674,838	$72,674,838	$72,674,838	$72,674,838	$72,674,838
Fuel costs ($/kWh)	$14,727,060	$14,727,060	$14,727,060	$14,727,060	$14,727,060	$14,727,060	$14,727,060	$14,727,060	$14,727,060	$14,727,060
Waste management costs ($/kWh)	$8,270,631	$8,270,631	$8,270,631	$8,270,631	$8,270,631	$8,270,631	$8,270,631	$8,270,631	$8,270,631	$8,270,631
Decommissioning costs ($/kWh)	$5,602,686	$5,602,686	$5,602,686	$5,602,686	$5,602,686	$5,602,686	$5,602,686	$5,602,686	$5,602,686	$5,602,686
Annual cash flow	$157,711,831	$157,711,831	$157,711,831	$157,711,831	$157,711,831	$157,711,831	$157,711,831	$157,711,831	$157,711,831	$157,711,831
Private cost ($/kWh)										
NPV annual private costs (5% public discount rate)										
Planning Assumptions										
Generating unit net capacity (MW)										
Average capacity factor (%)										
Electricity generated per year (kWh)	5,335,891,200	5,335,891,200	5,335,891,200	5,335,891,200	5,335,891,200	5,335,891,200	5,335,891,200	5,335,891,200	5,335,891,200	5,335,891,200
Operating life (years)										
Construction duration (years)										
Cost of long-term public debt										
Computable External Costs										
Severe accidents ($/kWh)										
Health costs associated with radioactive emissions ($/kWh)										
Total computable external costs ($/kWh)										
Total Social Costs ($/kWh)										

Appendix C (ii)		**First unit construction period**		**First unit comes online**										
Nuclear Refurbishment: Merchant Perspective	**Assumptions**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
Private Costs		**Year -2**	**Year -1**	**Year 1**	**Year 2**	**Year 3**	**Year 4**	**Year 5**	**Year 6**	**Year 7**	**Year 8**	**Year 9**	**Year 10**	**Year 11**
Revenue		$0	$0	$431,617,181	$431,617,181	$431,617,181	$431,617,181	$431,617,181	$431,617,181	$431,617,181	$431,617,181	$431,617,181	$431,617,181	$431,617,181
Capital costs ($/kW)	$1,922	$722,672,000	$722,672,000											
O&M costs ($/kWh)	$0.01362	$0	$0	$72,674,838	$72,674,838	$72,674,838	$72,674,838	$72,674,838	$72,674,838	$72,674,838	$72,674,838	$72,674,838	$72,674,838	$72,674,838
Fuel costs ($/kWh)	$0.00276	$0	$0	$14,727,060	$14,727,060	$14,727,060	$14,727,060	$14,727,060	$14,727,060	$14,727,060	$14,727,060	$14,727,060	$14,727,060	$14,727,060
Waste management costs ($/kWh)	$0.00155	$0	$0	$8,270,631	$8,270,631	$8,270,631	$8,270,631	$8,270,631	$8,270,631	$8,270,631	$8,270,631	$8,270,631	$8,270,631	$8,270,631
Decommissioning costs ($/kWh)	$0.00105	$0	$0	$5,602,686	$5,602,686	$5,602,686	$5,602,686	$5,602,686	$5,602,686	$5,602,686	$5,602,686	$5,602,686	$5,602,686	$5,602,686
Net income before depreciation and tax		$0	$0	$330,341,966	$330,341,966	$330,341,966	$330,341,966	$330,341,966	$330,341,966	$330,341,966	$330,341,966	$330,341,966	$330,341,966	$330,341,966
Depreciation	$111,180,308	$0	$0	$111,180,308	$111,180,308	$111,180,308	$111,180,308	$111,180,308	$111,180,308	$111,180,308	$111,180,308	$111,180,308	$111,180,308	$111,180,308
Taxes (%)	36%	$0	$0	$78,898,197	$78,898,197	$78,898,197	$78,898,197	$78,898,197	$78,898,197	$78,898,197	$78,898,197	$78,898,197	$78,898,197	$78,898,197
Net income after depreciation and tax		$0	$0	$140,263,461	$140,263,461	$140,263,461	$140,263,461	$140,263,461	$140,263,461	$140,263,461	$140,263,461	$140,263,461	$140,263,461	$140,263,461
Depreciation	$111,180,308	$0	$0	$111,180,308	$111,180,308	$111,180,308	$111,180,308	$111,180,308	$111,180,308	$111,180,308	$111,180,308	$111,180,308	$111,180,308	$111,180,308
Annual cash flow		-$722,672,000	-$722,672,000	$251,443,769	$251,443,769	$251,443,769	$251,443,769	$251,443,769	$251,443,769	$251,443,769	$251,443,769	$251,443,769	$251,443,769	$251,443,769
Private cost ($/kWh)	$0.081													
NPV annual private cost (13.0% merchant discount rate)	-$0.00													
Planning Assumptions														
Generating unit net capacity (MW)	752													
Average capacity factor (%)	81%													
Electricity generated per year (kWh)		0	0	5,335,891,200	5,335,891,200	5,335,891,200	5,335,891,200	5,335,891,200	5,335,891,200	5,335,891,200	5,335,891,200	5,335,891,200	5,335,891,200	5,335,891,200
Operating life (years)	26													
Construction duration (years)	2													
Cost of equity (%)	13.0%													
Computable External Costs														
Severe accidents ($/kWh)	$0.002													
Health costs associated with radioactive emissions ($/kWh)	$0.007													
Total computable external costs ($/kWh)	$0.009													
Total Social Costs ($/kWh)	$0.090													

Appendix C (ii)	**Second unit construction period**		**Second unit comes online**												
Nuclear Refurbishment: Merchant Perspective	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
Private Costs	**Year 12**	**Year 13**	**Year 14**	**Year 15**	**Year 16**	**Year 17**	**Year 18**	**Year 19**	**Year 20**	**Year 21**	**Year 22**	**Year 23**	**Year 24**	**Year 25**	**Year 26**
Revenue	$431,617,181	$431,617,181	$431,617,181	$431,617,181	$431,617,181	$431,617,181	$431,617,181	$431,617,181	$431,617,181	$431,617,181	$431,617,181	$431,617,181	$431,617,181	$431,617,181	$431,617,181
Capital costs ($/kW)	$722,672,000	$722,672,000													
O&M costs ($/kWh)	$72,674,838	$72,674,838	$72,674,838	$72,674,838	$72,674,838	$72,674,838	$72,674,838	$72,674,838	$72,674,838	$72,674,838	$72,674,838	$72,674,838	$72,674,838	$72,674,838	$72,674,838
Fuel costs ($/kWh)	$14,727,060	$14,727,060	$14,727,060	$14,727,060	$14,727,060	$14,727,060	$14,727,060	$14,727,060	$14,727,060	$14,727,060	$14,727,060	$14,727,060	$14,727,060	$14,727,060	$14,727,060
Waste management costs ($/kWh)	$8,270,631	$8,270,631	$8,270,631	$8,270,631	$8,270,631	$8,270,631	$8,270,631	$8,270,631	$8,270,631	$8,270,631	$8,270,631	$8,270,631	$8,270,631	$8,270,631	$8,270,631
Decommissioning costs ($/kWh)	$5,602,686	$5,602,686	$5,602,686	$5,602,686	$5,602,686	$5,602,686	$5,602,686	$5,602,686	$5,602,686	$5,602,686	$5,602,686	$5,602,686	$5,602,686	$5,602,686	$5,602,686
Net income before depreciation and tax	$330,341,966	$330,341,966	$330,341,966	$330,341,966	$330,341,966	$330,341,966	$330,341,966	$330,341,966	$330,341,966	$330,341,966	$330,341,966	$330,341,966	$330,341,966	$330,341,966	$330,341,966
Depreciation	$111,180,308	$111,180,308	$111,180,308	$111,180,308	$111,180,308	$111,180,308	$111,180,308	$111,180,308	$111,180,308	$111,180,308	$111,180,308	$111,180,308	$111,180,308	$111,180,308	$111,180,308
Taxes (%)	$78,898,197	$78,898,197	$78,898,197	$78,898,197	$78,898,197	$78,898,197	$78,898,197	$78,898,197	$78,898,197	$78,898,197	$78,898,197	$78,898,197	$78,898,197	$78,898,197	$78,898,197
Net income after depreciation and tax	$140,263,461	$140,263,461	$140,263,461	$140,263,461	$140,263,461	$140,263,461	$140,263,461	$140,263,461	$140,263,461	$140,263,461	$140,263,461	$140,263,461	$140,263,461	$140,263,461	$140,263,461
Depreciation	$111,180,308	$111,180,308	$111,180,308	$111,180,308	$111,180,308	$111,180,308	$111,180,308	$111,180,308	$111,180,308	$111,180,308	$111,180,308	$111,180,308	$111,180,308	$111,180,308	$111,180,308
Annual cash flow	-$471,228,231	-$471,228,231	$251,443,769	$251,443,769	$251,443,769	$251,443,769	$251,443,769	$251,443,769	$251,443,769	$251,443,769	$251,443,769	$251,443,769	$251,443,769	$251,443,769	$251,443,769
Private cost ($/kWh)															
NPV annual private cost (13.0% merchant discount rate)															
Planning Assumptions															
Generating unit net capacity (MW)															
Average capacity factor (%)															
Electricity generated per year (kWh)	5,335,891,200	5,335,891,200	5,335,891,200	5,335,891,200	5,335,891,200	5,335,891,200	5,335,891,200	5,335,891,200	5,335,891,200	5,335,891,200	5,335,891,200	5,335,891,200	5,335,891,200	5,335,891,200	5,335,891,200
Operating life (years)															
Construction duration (years)															
Cost of equity (%)															
Computable External Costs															
Severe accidents ($/kWh)															
Health costs associated with radioactive emissions ($/kWh)															
Total computable external costs ($/kWh)															
Total Social Costs ($/kWh)															

Appendix C (ii)		Construction period						Unit comes online
Nuclear New Unit: Public Perspective	**Assumptions**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**
Private Costs		**Year -6**	**Year -5**	**Year -4**	**Year -3**	**Year -2**	**Year -1**	**Year 1**
Revenue		$0	$0	$0	$0	$0	$0	$251,673,648
Capital costs ($/kW)	$3,003	$168,168,000	$441,441,000	$569,669,100	$412,011,600	$252,252,000	$151,351,200	$107,207,100
O&M costs ($/kWh)	$0.01362	$0	$0	$0	$0	$0	$0	$67,649,450
Fuel costs ($/kWh)	$0.00276	$0	$0	$0	$0	$0	$0	$13,708,699
Waste management costs ($/kWh)	$0.00155	$0	$0	$0	$0	$0	$0	$7,698,726
Decommissioning costs ($/kWh)	$0.00105	$0	$0	$0	$0	$0	$0	$5,215,266
Annual Cash flow		-$168,168,000	-$441,441,000	-$569,669,100	-$412,011,600	-$252,252,000	-$151,351,200	$50,194,407
Private cost ($/kWh)	$0.051							
NPV annual private costs (5% public discount rate)	$0.00							
Planning Assumptions								
Generating unit net capacity (MW)	700							
Average capacity factor (%)	81%							
Electricity generated per year (kWh)		0	0	0	0	0	0	4,966,920,000
Operating life (years)	29							
Construction duration (years)	6							
Cost of long-term public debt	5%							
Computable External Costs								
Severe accidents ($/kWh)	$0.002							
Health costs associated with radioactive emissions ($/kWh)	$0.007							
Total computable external costs ($/kWh)	$0.009							
Total Social Costs ($/kWh)	$0.060							

	2013	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Private Costs	**Year 2**	**Year 3**	**Year 4**	**Year 5**	**Year 6**	**Year 7**	**Year 8**	**Year 9**	**Year 10**	**Year 11**	**Year 12**	**Year 13**	**Year 14**	**Year 15**
Revenue	$251,673,648	$251,673,648	$251,673,648	$251,673,648	$251,673,648	$251,673,648	$251,673,648	$251,673,648	$251,673,648	$251,673,648	$251,673,648	$251,673,648	$251,673,648	$251,673,648
Capital costs ($/kW)														
O&M costs ($/kWh)	$67,649,450	$67,649,450	$67,649,450	$67,649,450	$67,649,450	$67,649,450	$67,649,450	$67,649,450	$67,649,450	$67,649,450	$67,649,450	$67,649,450	$67,649,450	$67,649,450
Fuel costs ($/kWh)	$13,708,699	$13,708,699	$13,708,699	$13,708,699	$13,708,699	$13,708,699	$13,708,699	$13,708,699	$13,708,699	$13,708,699	$13,708,699	$13,708,699	$13,708,699	$13,708,699
Waste management costs ($/kWh)	$7,698,726	$7,698,726	$7,698,726	$7,698,726	$7,698,726	$7,698,726	$7,698,726	$7,698,726	$7,698,726	$7,698,726	$7,698,726	$7,698,726	$7,698,726	$7,698,726
Decommissioning costs ($/kWh)	$5,215,266	$5,215,266	$5,215,266	$5,215,266	$5,215,266	$5,215,266	$5,215,266	$5,215,266	$5,215,266	$5,215,266	$5,215,266	$5,215,266	$5,215,266	$5,215,266
Annual Cash flow	$157,401,507	$157,401,507	$157,401,507	$157,401,507	$157,401,507	$157,401,507	$157,401,507	$157,401,507	$157,401,507	$157,401,507	$157,401,507	$157,401,507	$157,401,507	$157,401,507
Electricity generated per year (kWh)	4,966,920,000	4,966,920,000	4,966,920,000	4,966,920,000	4,966,920,000	4,966,920,000	4,966,920,000	4,966,920,000	4,966,920,000	4,966,920,000	4,966,920,000	4,966,920,000	4,966,920,000	4,966,920,000

	2027	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
Private Costs	**Year 16**	**Year 17**	**Year 18**	**Year 19**	**Year 20**	**Year 21**	**Year 22**	**Year 23**	**Year 24**	**Year 25**	**Year 26**	**Year 27**	**Year 28**	**Year 29**
Revenue	$251,673,648	$251,673,648	$251,673,648	$251,673,648	$251,673,648	$251,673,648	$251,673,648	$251,673,648	$251,673,648	$251,673,648	$251,673,648	$251,673,648	$251,673,648	$251,673,648
Capital costs ($/kW)														
O&M costs ($/kWh)	$67,649,450	$67,649,450	$67,649,450	$67,649,450	$67,649,450	$67,649,450	$67,649,450	$67,649,450	$67,649,450	$67,649,450	$67,649,450	$67,649,450	$67,649,450	$67,649,450
Fuel costs ($/kWh)	$13,708,699	$13,708,699	$13,708,699	$13,708,699	$13,708,699	$13,708,699	$13,708,699	$13,708,699	$13,708,699	$13,708,699	$13,708,699	$13,708,699	$13,708,699	$13,708,699
Waste management costs ($/kWh)	$7,698,726	$7,698,726	$7,698,726	$7,698,726	$7,698,726	$7,698,726	$7,698,726	$7,698,726	$7,698,726	$7,698,726	$7,698,726	$7,698,726	$7,698,726	$7,698,726
Decommissioning costs ($/kWh)	$5,215,266	$5,215,266	$5,215,266	$5,215,266	$5,215,266	$5,215,266	$5,215,266	$5,215,266	$5,215,266	$5,215,266	$5,215,266	$5,215,266	$5,215,266	$5,215,266
Annual Cash flow	$157,401,507	$157,401,507	$157,401,507	$157,401,507	$157,401,507	$157,401,507	$157,401,507	$157,401,507	$157,401,507	$157,401,507	$157,401,507	$157,401,507	$157,401,507	$157,401,507
Electricity generated per year (kWh)	4,966,920,000	4,966,920,000	4,966,920,000	4,966,920,000	4,966,920,000	4,966,920,000	4,966,920,000	4,966,920,000	4,966,920,000	4,966,920,000	4,966,920,000	4,966,920,000	4,966,920,000	4,966,920,000

Appendix C (ii)		Construction period						Unit comes online
Nuclear New Unit: Merchant Perspective	**Assumptions**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**
Private Costs		**Year -6**	**Year -5**	**Year -4**	**Year -3**	**Year -2**	**Year -1**	**Year 1**
Revenue		$0	$0	$0	$0	$0	$0	$661,953,944
Capital costs ($/kW)	$3,003	$168,168,000	$441,441,000	$569,669,100	$412,011,600	$252,252,000	$151,351,200	$107,207,100
O&M costs ($/kWh)	$0.01362	$0	$0	$0	$0	$0	$0	$67,649,450
Fuel costs ($/kWh)	$0.00276	$0	$0	$0	$0	$0	$0	$13,708,699
Waste management costs ($/kWh)	$0.00155	$0	$0	$0	$0	$0	$0	$7,698,726
Decommissioning costs ($/kWh)	$0.00105	$0	$0	$0	$0	$0	$0	$5,215,266
Net income before depreciation and tax		$0	$0	$0	$0	$0	$0	$567,681,802
Depreciation	$72,486,207	$0	$0	$0	$0	$0	$0	$72,486,207
Taxes	36%	$0	$0	$0	$0	$0	$0	$178,270,414
Net income after depreciation and tax		$0	$0	$0	$0	$0	$0	$316,925,181
Depreciation	$72,486,207	$0	$0	$0	$0	$0	$0	$72,486,207
Annual Cash flow		-$168,168,000	-$441,441,000	-$569,669,100	-$412,011,600	-$252,252,000	-$151,351,200	$282,204,288
Private cost ($/kWh)	$0.133							
NPV annual private cost (13.0% merchant discount rate)	$0.00							
Planning Assumptions								
Generating unit net capacity (MW)	700							
Average capacity factor (%)	81%							
Electricity generated per year (kWh)		0	0	0	0	0	0	4,966,920,000
Operating life (years)	29							
Construction duration (years)	6							
Cost of equity (%)	13.0%							
Computable External Costs								
Severe accidents ($/kWh)	$0.002							
Health costs associated with radioactive emissions ($/kWh)	$0.007							
Total computable external costs ($/kWh)	$0.009							
Total Social Costs ($/kWh)	$0.142							

	2013	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Private Costs	**Year 2**	**Year 3**	**Year 4**	**Year 5**	**Year 6**	**Year 7**	**Year 8**	**Year 9**	**Year 10**	**Year 11**	**Year 12**	**Year 13**	**Year 14**	**Year 15**
Revenue	$661,953,944	$661,953,944	$661,953,944	$661,953,944	$661,953,944	$661,953,944	$661,953,944	$661,953,944	$661,953,944	$661,953,944	$661,953,944	$661,953,944	$661,953,944	$661,953,944
Capital costs ($/kW)														
O&M costs ($/kWh)	$67,649,450	$67,649,450	$67,649,450	$67,649,450	$67,649,450	$67,649,450	$67,649,450	$67,649,450	$67,649,450	$67,649,450	$67,649,450	$67,649,450	$67,649,450	$67,649,450
Fuel costs ($/kWh)	$13,708,699	$13,708,699	$13,708,699	$13,708,699	$13,708,699	$13,708,699	$13,708,699	$13,708,699	$13,708,699	$13,708,699	$13,708,699	$13,708,699	$13,708,699	$13,708,699
Waste management costs ($/kWh)	$7,698,726	$7,698,726	$7,698,726	$7,698,726	$7,698,726	$7,698,726	$7,698,726	$7,698,726	$7,698,726	$7,698,726	$7,698,726	$7,698,726	$7,698,726	$7,698,726
Decommissioning costs ($/kWh)	$5,215,266	$5,215,266	$5,215,266	$5,215,266	$5,215,266	$5,215,266	$5,215,266	$5,215,266	$5,215,266	$5,215,266	$5,215,266	$5,215,266	$5,215,266	$5,215,266
Net income before depreciation and tax	$567,681,802	$567,681,802	$567,681,802	$567,681,802	$567,681,802	$567,681,802	$567,681,802	$567,681,802	$567,681,802	$567,681,802	$567,681,802	$567,681,802	$567,681,802	$567,681,802
Depreciation	$72,486,207	$72,486,207	$72,486,207	$72,486,207	$72,486,207	$72,486,207	$72,486,207	$72,486,207	$72,486,207	$72,486,207	$72,486,207	$72,486,207	$72,486,207	$72,486,207
Taxes	$178,270,414	$178,270,414	$178,270,414	$178,270,414	$178,270,414	$178,270,414	$178,270,414	$178,270,414	$178,270,414	$178,270,414	$178,270,414	$178,270,414	$178,270,414	$178,270,414
Net income after depreciation and tax	$316,925,181	$316,925,181	$316,925,181	$316,925,181	$316,925,181	$316,925,181	$316,925,181	$316,925,181	$316,925,181	$316,925,181	$316,925,181	$316,925,181	$316,925,181	$316,925,181
Depreciation	$72,486,207	$72,486,207	$72,486,207	$72,486,207	$72,486,207	$72,486,207	$72,486,207	$72,486,207	$72,486,207	$72,486,207	$72,486,207	$72,486,207	$72,486,207	$72,486,207
Annual Cash flow	$389,411,388	$389,411,388	$389,411,388	$389,411,388	$389,411,388	$389,411,388	$389,411,388	$389,411,388	$389,411,388	$389,411,388	$389,411,388	$389,411,388	$389,411,388	$389,411,388
Electricity generated per year (kWh)	4,966,920,000	4,966,920,000	4,966,920,000	4,966,920,000	4,966,920,000	4,966,920,000	4,966,920,000	4,966,920,000	4,966,920,000	4,966,920,000	4,966,920,000	4,966,920,000	4,966,920,000	4,966,920,000

	2027	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
Private Costs	**Year 16**	**Year 17**	**Year 18**	**Year 19**	**Year 20**	**Year 21**	**Year 22**	**Year 23**	**Year 24**	**Year 25**	**Year 26**	**Year 27**	**Year 28**	**Year 29**
Revenue	$661,953,944	$661,953,944	$661,953,944	$661,953,944	$661,953,944	$661,953,944	$661,953,944	$661,953,944	$661,953,944	$661,953,944	$661,953,944	$661,953,944	$661,953,944	$661,953,944
Capital costs ($/kW)														
O&M costs ($/kWh)	$67,649,450	$67,649,450	$67,649,450	$67,649,450	$67,649,450	$67,649,450	$67,649,450	$67,649,450	$67,649,450	$67,649,450	$67,649,450	$67,649,450	$67,649,450	$67,649,450
Fuel costs ($/kWh)	$13,708,699	$13,708,699	$13,708,699	$13,708,699	$13,708,699	$13,708,699	$13,708,699	$13,708,699	$13,708,699	$13,708,699	$13,708,699	$13,708,699	$13,708,699	$13,708,699
Waste management costs ($/kWh)	$7,698,726	$7,698,726	$7,698,726	$7,698,726	$7,698,726	$7,698,726	$7,698,726	$7,698,726	$7,698,726	$7,698,726	$7,698,726	$7,698,726	$7,698,726	$7,698,726
Decommissioning costs ($/kWh)	$5,215,266	$5,215,266	$5,215,266	$5,215,266	$5,215,266	$5,215,266	$5,215,266	$5,215,266	$5,215,266	$5,215,266	$5,215,266	$5,215,266	$5,215,266	$5,215,266
Net income before depreciation and tax	$567,681,802	$567,681,802	$567,681,802	$567,681,802	$567,681,802	$567,681,802	$567,681,802	$567,681,802	$567,681,802	$567,681,802	$567,681,802	$567,681,802	$567,681,802	$567,681,802
Depreciation	$72,486,207	$72,486,207	$72,486,207	$72,486,207	$72,486,207	$72,486,207	$72,486,207	$72,486,207	$72,486,207	$72,486,207	$72,486,207	$72,486,207	$72,486,207	$72,486,207
Taxes	$178,270,414	$178,270,414	$178,270,414	$178,270,414	$178,270,414	$178,270,414	$178,270,414	$178,270,414	$178,270,414	$178,270,414	$178,270,414	$178,270,414	$178,270,414	$178,270,414
Net income after depreciation and tax	$316,925,181	$316,925,181	$316,925,181	$316,925,181	$316,925,181	$316,925,181	$316,925,181	$316,925,181	$316,925,181	$316,925,181	$316,925,181	$316,925,181	$316,925,181	$316,925,181
Depreciation	$72,486,207	$72,486,207	$72,486,207	$72,486,207	$72,486,207	$72,486,207	$72,486,207	$72,486,207	$72,486,207	$72,486,207	$72,486,207	$72,486,207	$72,486,207	$72,486,207
Annual Cash flow	$389,411,388	$389,411,388	$389,411,388	$389,411,388	$389,411,388	$389,411,388	$389,411,388	$389,411,388	$389,411,388	$389,411,388	$389,411,388	$389,411,388	$389,411,388	$389,411,388
Electricity generated per year (kWh)	4,966,920,000	4,966,920,000	4,966,920,000	4,966,920,000	4,966,920,000	4,966,920,000	4,966,920,000	4,966,920,000	4,966,920,000	4,966,920,000	4,966,920,000	4,966,920,000	4,966,920,000	4,966,920,000

Appendix C (iii): Computable External Burden Assessment	Source														
Natural Gas	**Rowe et al. (1995)**	**ORNL & RfF (1998)***	**Maddison (1999)**	**EC (1999b) Spain**	**EC (1999b) Greece**	**EC (1999b) Italy**	**EC (1999b) Netherlands**	**EC (1999b) Norway**	**EC (1999b) Portugal**	**EC (2004) Beligium**	**EC (2004) Germany**	**EC (2004) France**	**EC (2004) UK**	**DSS for MOE (2005)**	**Average**
Climate change costs	n/a	n/a	0.6 mECU/kWh	7.2 mECU/kWh	3.6 mECU/kWh	7.86 mECU/kWh	7.4 mECU/kWh	7.4 mECU/kWh	7.8 mECU/kWh	0.74 Euro cents/kWh	0.66 Euro cents/kWh	0.7 Euro cents/kWh	0.75 Euro cents/kWh	CDN$5.29/MWh	
% of computable external costs	n/a	n/a	67%	66%	54%	53%	76%	96%	95%	82%	71%	57%	95%	26%	70%
Premature mortality costs associated with air pollution	0.127 US mills/kWh	0.016 US mills/kWh	0.2 mECU/kWh	2.86 mECU/kWh	1.79 mECU/kWh	5.5 mECU/kWh	1.73 mECU/kWh	0.254 mECU/kWh	0.2 mECU/kWh	0.12 Euro cents/kWh	0.07 Euro cents/kWh	0.07 Euro cents/kWh	0.05 Euro cents/kWh	CDN$15/MWh	
% of computable external costs	56%	10%	22%	26%	27%	37%	18%	3%	2%	13%	8%	6%	6%	74%	22%
Morbidity costs associated with air pollution	0.033 US mills/kWh	0.087 US mills/kWh	n/a	0.54 mECU/kWh	0.6 mECU/kWh	0.99 mECU/kWh	0.44 mECU/kWh	0.04 mECU/kWh	0.05 mECU/kWh	0.02 Euro cents/kWh	0.03 Euro cents/kWh	0.04 Euro cents/kWh	(0.01) Euro cents/kWh	0	
% of computable external costs	14%	53%	n/a	5%	9%	7%	4%	1%	1%	2%	3%	3%	-1%	0%	8%
Costs associated with reduction in crop yield	0	0.06 US mills/kWh	n/a	0.094 mECU/kWh	0.19 mECU/kWh	0.15 mECU/kWh	0.11 mECU/kWh	0	0.011 mECU/kWh	(0.02) Euro cents/kWh	0	0.01 Euro cents/kWh	(0.02) Euro cents/kWh	0	
% of computable external costs	0%	37%	n/a	1%	3%	1%	1%	0%	0%	-2%	0%	1%	-3%	0%	3%
Climate change costs (non-power conversion stage)	n/a	n/a	n/a	0.12 mECU/kWh	0.02 mECU/kWh	0.26 mECU/kWh	0.2 mECU/kWh	0	0.15 mECU/kWh	0.04 Euro cents/kWh	0.1 Euro cents/kWh	0.34 Euro cents/kWh	0.02 Euro cents/kWh	0	
% of computable external costs	n/a	n/a	n/a	1%	0%	2%	2%	0%	2%	4%	11%	28%	3%	0%	5%
Premature mortality and morbidity costs (non-power conversion stage)	0	0	0	0.00018 mECU/kWh	0	0.058 mECU/kWh	0.0091 mECU/kWh	0	0	0	0.07 Euro cents/kWh	0.07 Euro cents/kWh	0	0	
% of computable external costs	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	8%	6%	0%	0%	1%
Other external costs	0.068 US mills/kWh	0	0.1 mECU/kWh	0.18 mECu/kWh	0.47 mECU/kWh	0.047 mECU/kWh	0.018 mECU/kWh	0.03 mECU/kWh	0.00396 mECU/kWh	0.003 Euro cents/kWh	0.003 Euro cents/kWh	0.001 Euro cents/kWh	0.002 Euro cents/kWh	0	
% of computable external costs	30%	0%	11%	1%	7%	0%	0%	0%	0%	0%	0%	0%	0%	0%	4%
Occupational health costs	0	0	0	0.049 mECU/kWh	0.176 mECU/kWh	0.099 mECU/kWh	0.1 mECU/kWh	0.004 mECU/kWh	0.08713 mECU/kWh	0	0	0	0	0	
% of computable external costs (if included)	0%	0%	0%	0%	3%	1%	1%	0%	1%	0%	0%	0%	0%	0%	
% of computable external costs	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Computable external costs (orignial estimate)	0.228 US mills/kWh	0.163 US mills/kWh	0.9 mECU/kWh	10.9 mECU/kWh	6.9 mECU/kWh	14.96 mECU/kWh	9.9 mECU/kWh	7.73 mECU/kWh	8.3 mECU/kWh	0.903 Euro cents/kWh	0.933 Euro cents/kWh	1.231 Euro cents/kWh	0.792 Euro cents/kWh	CDN$20.29/MWh	
Computable external costs (after occupational costs are subtracted)	0.228 US mills/kWh	0.163 US mills/kWh	0.9 mECU/kWh	10.85 mECU/kWh	6.72 mECU/kWh	14.87 mECU/kWh	9.8 mECU/kWh	7.73 mECU/kWh	8.21 mECU/kWh	0.903 Euro cents/kWh	0.933 Euro cents/kWh	1.231 Euro cents/kWh	0.792 Euro cents/kWh	CDN$20.29/MWh	
Sum		* (southeast site)													112%

note (a): individual study percentages may not add up to 100% due to rounding.
note (b): the sum of the averages does not add up to 100% due to the presence of n/a (not applicable) for particular external burdens.The term n/a is used to signify that the original authors decided not to evaluate a particular external burden as opposed to estimating a value of zero.
note (c): costs are expressed in base year dollars obtained from original studies.

Appendix C (iii): Computable External Burden Assessment	Source							
Wind	**Rowe et al. (1995)**	**EC (1999b) Germany**	**EC (1999b) Denmark***	**EC (1999b) Spain**	**EC (1999b) Greece**	**EC (1999b) Norway**	**EC (1999b) UK**	**Average**
Premature mortality costs associated with air pollution (non-power conversion stage)	n/a	0.24 mECU/kWh	0.17 mECU/kWh	0.57 mECU/kWh	0.84 mECU/kWh	0.365 mECU/kWh	n/a	
% of computable external costs	n/a	56%	22%	83%	36%	79%	n/a	55%
Climate change costs (non-power conversion stage)	n/a	0.12 mECU/kWh	0.26 mECU/kWh	0.093 mECU/kWh	0.15 mECU/kWh	0.09 mECU/kWh	0.16 mECU/kWh	
% of computable external costs	n/a	28%	34%	13%	6%	20%	15%	19%
Miscellaneous external costs								
Costs associated with land use	0.01 US mills/kWh	n/a	n/a	n/a	0.14 mECU/kWh	n/a	n/a	
% of computable external costs	100%	n/a	n/a	n/a	6%	n/a	n/a	
Costs associated with noise disturbance	n/a	0.031 mECU/kWh	0.02 mECU/kWh	0.008 mECU/kWh	1.12 mECU/kWh	0	0.07 mECU/kWh	
% of computable external costs	n/a	7%	3%	1%	48%	0%	7%	
Costs associated with visual disturbance	n/a	n/a	0.17 mECU/kWh	0	0	0	n/a	
% of computable external costs	n/a	n/a	22%	0%	0%	0%	n/a	
Total miscellaneous external costs (land use, noise & visual)	100%	7%	25%	1%	54%	0%	7%	28%
Morbidity costs associated with air pollution	n/a	0.03 mECU/kWh	0.12 mECU/kWh	0	0	0	0	
% of computable external costs	n/a	7%	16%	0%	0%	0%	0%	4%
Other costs	0	0.0033 mECU/kWh	0.03 mECU/kWh	0	0.02 mECU/kWh	0.0093 mECU/kWh	0.79 mECU/kWh	
% of computable external costs	0%	0%	4%	0%	1%	2%	76%	12%
Occupational health costs	n/a	0.044 mECU/kWh	0.03 mECU/kWh	1.11 mECU/kWh	0.08 mECU/kWh	0.0413 mECU/kWh	0.26 mECU/kWh	
% of computable external costs (if included)	n/a	10%	4%	62%	3%	9%	20%	
% of computable external costs	n/a	0%	0%	0%	0%	0%	0%	0%
Computable external costs (orignial estimate)	0.01 US mills/kWh	0.47 mECU/kWh	0.8 mECU/kWh	1.8 mECU/kWh	2.4 mECU/kWh	0.5 mECU/kWh	1.3 mECU/kWh	
Computable external costs (after occupational costs are subtracted)	0.01 US mills/kWh	0.43 mECU/kWh	0.77 mECU/kWh	0.69 mECU/kWh	2.32 mECU/kWh	0.46 mECU/kWh	1.04 mECU/kWh	
Sum			* (on-land)					118%

note (a): individual study percentages may not add up to 100% due to rounding.
note (b): the sum of the averages does not add up to 100% due to the presence of n/a (not applicable) for particular external burdens.The term n/a is used to signify that the original authors decided not to evaluate a particular external burden as opposed to estimating a value of zero.
note (c): costs are expressed in base year dollars obtained from original studies.

Appendix C (iii): Computable External Burden Assessment	Source									
Nuclear refurbishment and new generation	**Ottinger et al. (1990)**	**Chernick et al. (1993)**	**Rowe et al. (1995)**	**Berry et al. (1998)**	**ORNL & RfF (1998)**	**Spadaro & Rabl (1998)**	**EC (1999b) Belgium***	**EC (1999b) Germany**	**EC (1999b) Netherlands**	**Average**
Public health costs (fatal, non-fatal cancer & genetic effects) from radioactive emissions (non-power conversion stage)	n/a	0.4 CDN cents/kWh	0.002 US mills/kWh	2 mECU/kWh	0.0145 US mills/kWh	1.93 mECU/kWh	3.3 mECU/kWh	3.5 mECU/kWh	7.1 mECU/kWh	
% of computable external costs	n/a	15%	7%	87%	8%	81%	84%	76%	99%	57%
Costs associated with severe nuclear accidents	2.3 US cents/kWh	2.4 CDN cents/kWh	0.015 US mills/kWh	n/a	0.1038 US mills/kWh	0.005 mECU/kWh	0.18 mECU/kWh	0.0034 mECU/kWh	0.058 mECU/kWh	
% of computable external costs	99%	85%	50%	n/a	54%	0%	5%	0%	1%	37%
Public health costs (fatal, non-fatal cancer & genetic effects) from radioactive emissions (power conversion stage)	0.001 US cents/kWh	n/a	0	0.079 mECU/kWh	0.000036 US mills/kWh	0.44 mECU/kWh	0.2 mECU/kWh	0.059 mECU/kWh	0	
% of computable external costs	0%	n/a	0%	3%	0%	19%	5%	1%	0%	4%
Climate change costs (non-power conversion stage)	n/a	n/a	n/a	0.21 mECU/kWh	n/a	n/a	0.08 mECU/kWh	0.35 mECU/kWh	n/a	
% of computable external costs	n/a	n/a	n/a	9%	n/a	n/a	2%	8%	n/a	6%
Public health costs from non-radioactive emissions	n/a	n/a	n/a	0	n/a	n/a	0.17 mECU/kWh	0.56 mECU/kWh	n/a	
% of computable external costs	n/a	n/a	n/a	0%	n/a	n/a	4%	12%	n/a	5%
Other external costs	0.01 US cents/kWh	0	0.013 US mills/kWh	0	0.07252 US mills/kWh	0	0	0.00786 mECU/kWh	0	
% of computable external costs	0%	0%	43%	0%	38%	0%	0%	0%	0%	9%
Decommissioning costs	0.5 US cents/kWh	n/a	n/a	n/a	0.00299 US mills/kWh	n/a	n/a	n/a	n/a	
% of computable external costs if included	18%	n/a	n/a	n/a	2%	n/a	n/a	n/a	n/a	
% of computable external costs	0%	n/a	n/a	n/a	0%	n/a	n/a	n/a	n/a	0%
Occupational health costs from radioactive and non-radioactive emissions	0.097 US cents/kWh	0	0.082 US mills/kWh	0.1044 mECU/kWh	0.09958 US mills/kWh	0.15 mECU/kWh	0.19 mECU/kWh	0.123 mECU/kWh	0.18 mECU/kWh	
% of computable external costs if included	3%	0%	73%	4%	48%	6%	5%	3%	2%	
% of computable external costs	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Computable external costs (orignial estimate)	2.91 US cents/kWh	2.8 CDN cents/kWh	0.112 US mills/kWh	2.4 mECU/kWh	0.29343 US mills/kWh	2.52 mECU/kWh	4.12 mECU/kWh	4.7 mECU/kWh	7.34 mECU/kWh	
Computable external costs (after decommissioning and occupational costs are subtracted)	2.313 US cents/kWh	2.8 CDN cents/kWh	0.03 US mills/kWh	2.3 mECU/kWh	0.19086 US mills/kWh	2.37 mECU/kWh	3.93 mECU/kWh	4.58 mECU/kWh	7.16 mECU/kWh	
Sum							* (open fuel cycle)			118%

note (a): individual study percentages may not add up to 100% due to rounding.
note (b): the sum of the averages does not add up to 100% due to the presence of n/a (not applicable) for particular external burdens.The term n/a is used to signify that the original authors decided not to evaluate a particular external burden as opposed to estimating a value of zero.
note (c): costs are expressed in base year dollars obtained from original studies.

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